

**U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
PB-299 179**

**Energy from the West: Energy Resource
Development Systems Report
Volume III: Oil Shale**

Oklahoma Univ, Norman Science and Public Policy Program

Prepared for

**Environmental Protection Agency, Washington, DC Office of Energy, Minerals
and Industry**

Mar 79

United States
Environmental Protection
Agency

Office of Energy, Minerals, and
Industry
Washington DC 20460

EPA 600 / 79-060c
March 1979

Research and Development

PB 299179



Energy from the West

Energy Resource
Development
Systems Report
Volume III: Oil Shale

Interagency
Energy/Environment
R&D Program
Report

REPRODUCED BY
**NATIONAL TECHNICAL
INFORMATION SERVICE**
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-79-060c		2. 		3. RECORD NUMBER PB299179	
4. TITLE AND SUBTITLE ENERGY FROM THE WEST: ENERGY RESOURCE DEVELOPMENT SYSTEMS REPORT - VOLUME III: OIL SHALE				5. REPORT DATE March 1979 issuing date	
				6. PERFORMING ORGANIZATION CODE	
7. AUTHOR(S) I.L. White; M.A. Chartock; R.L. Leonard; S.C. Ballard; M. Gilliland; T.A. Hall; E.J. Malecki; E.B. Rappaport; R.W. Rycroft; R.K. Freed; G.D. Miller				8. PERFORMING ORGANIZATION REPORT NO.	
9. PERFORMING ORGANIZATION NAME AND ADDRESS Science & Public Policy Program The Radian Corp. University of Oklahoma P.O. Box 9948 601 Elm, Room 432 Austin, TX 78766 Norman, OK 73019				10. PROGRAM ELEMENT NO. INE827	
				11. CONTRACT/GRANT NO. 68-01-1916	
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Office of Research & Development Office of Energy, Minerals & Industry Washington, D.C. 20460				13. TYPE OF REPORT AND PERIOD COVERED FINAL 1975 - 1978	
				14. SPONSORING AGENCY CODE EPA/600/17	
15. SUPPLEMENTARY NOTES This project is part of the EPA-planned and coordinated Federal Interagency Energy/Environment R&D Program.					
16. ABSTRACT <u>ABSTRACT</u> This report describes the technologies likely to be used for development of coal, oil shale, uranium, oil, natural gas, and geothermal resources in eight western states (Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming). It is part of a three-year "Technology Assessment of Western Energy Resource Development." The study examines the development of these energy resources in the eight states from the present to the year 2000. Other reports describe the analytic structure and conduct of the study, the impacts likely to result when these resources are developed, and analyze policy problems and issues likely to result from that development. The report is published in six volumes. Volume 1 describes the study, the technological activities such as exploration, extraction, and conversion for developing the resource, and laws and regulations which affect the development of more than one of the six resources considered in the study. The remaining five volumes are resource specific: Volume 2, Coal; Volume 3, Oil Shale; Volume 4, Uranium; Volume 5, Oil and Natural Gas; and Volume 6, Geothermal. Each of these volumes provides information on input materials and labor requirements, outputs, residuals, energy requirements, economic costs, and resource specific state and federal laws and regulations.					
17. (Circle One or More) KEY WORDS AND DOCUMENT ANALYSIS					
a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS		c. COSATI Field/Group	
Energy Conversion		Energy Cycle: Oil Shale Extraction, Processing, Conversion and Transportation Integrated Assessment		6F 8A 8F 8H 10A 10B 7B 7C 13B	
18. DISTRIBUTION STATEMENT Unlimited		19. SECURITY CLASS (This Report) Unclassified		21. NO. OF PAGES 328	
		20. SECURITY CLASS (This page) Unclassified		22. PRICE PC15 / MF AC1	

Energy From the West Energy Resource Development Systems Report

Volume III: Oil Shale

By
Science and Public Policy Program
University of Oklahoma

Irvin L. White
Michael A. Chartock
R. Leon Leonard
Steven C. Ballard
Martha Gilliland
Timothy A. Hall

Edward J. Malecki
Edward B. Rappaport
Robert W. Rycroft
Rodney K. Freed
Gary D. Miller

Managers,
Energy Resource Development Systems
R. Leon Leonard, Science and Public Policy
University of Oklahoma
Clinton E. Burklin

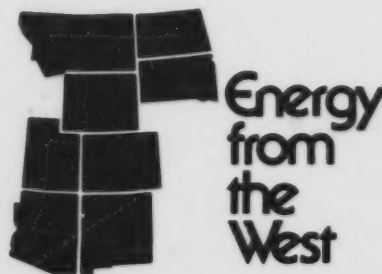
C. Patrick Bartosh
Clinton E. Burklin
William R. Hearn

Gary D. Jones
William J. Moltz
Patrick J. Murin

Prepared for:
Office of Research and Development
U.S. Environmental Protection Agency
Washington, D.C. 10460

Project Officer:
Steven E. Plotkin
Office of Energy, Minerals and Industry

Contract Number 68-01-1916



DISCLAIMER

This report has been reviewed by the Office of Energy, Minerals and Industry, U.S. Environmental Protection Agency, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the U.S. Environmental Protection Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

FORWARD

The production of electricity and fossil fuels inevitably impacts Man and his environment. The nature of these impacts must be thoroughly understood if balanced judgements concerning future energy development in the United States are to be made. The Office of Energy, Minerals and Industry (OEMI), in its role as coordinator of the Federal Energy/Environment Research and Development Program, is responsible for producing the information on health and ecological effects - and methods for mitigating the adverse effects - that is critical to developing the Nation's environmental and energy policy. OEMI's Integrated Assessment Program combines the results of research projects within the Energy/Environment Program with research on the socioeconomic and political/institutional aspects of energy development, and conducts policy - oriented studies to identify the tradeoffs among alternative energy technologies, development patterns, and impact mitigation measures.

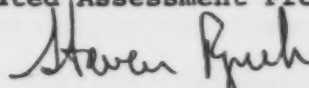
The Integrated Assessment Program has supported several "technology assessments" in fulfilling its mission. Assessments have been supported which explore the impact of future energy development on both a nationwide and a regional scale. Current assessments include national assessments of future development of the electric utility industry and of advanced coal technologies (such as fluidized bed combustion). Also, the Program is conducting assessments concerned with multiple-resource development in two "energy resource areas":

- o Western coal states
- o Lower Ohio River Basin

This report, which describes the technologies likely to be used for developing six energy resources in eight western states, is one of three major reports produced by the "Technology Assessment of Western Energy Resource Development" study. (The other two reports are an impact analysis report and a policy analysis report.) The report is divided into six volumes. The first volume describes the study, the organization of this report and briefly outlines laws and regulations which affect the development of more than one of the six resources considered in the study. The remaining five volumes are resource specific and describe the resource base, the technological activities such as exploration, extraction and conversion for developing the resource, and resource specific laws and regula-

tions. This report is both a compendium of information and a planning handbook. The descriptions of the various energy development technologies and the extensive compilations of technical baseline information are written to be easily understood by laypersons. Both professional planners and interested citizens should find it quite easy to use the information presented in this report to make general but useful comparisons of energy technologies and energy development alternatives, especially when this report is used in conjunction with the impact and policy analysis reports mentioned above.

Your review and comments on these reports are welcome. Such comments will help us to improve the usefulness of the products produced by our Integrated Assessment Program.



Steven R. Reznick

Acting Deputy Assistant Administrator
for Energy, Minerals and Industry

PREFACE

This Energy Resource Development System (ERDS) report has been prepared as part of "A Technology Assessment of Western Energy Resource Development" being conducted by an interdisciplinary research team from the Science and Public Policy Program (S&PP) of the University of Oklahoma for the Office of Energy, Minerals and Industry (OEMI), Office of Research and Development, U.S. Environmental Protection Agency (EPA). This study is one of several conducted under the Integrated Assessment Program established by OEMI in 1975. Recommended by an interagency task force, the purpose of the Program is to identify economically, environmentally, and socially acceptable energy development alternatives. The overall purposes of this particular study were to identify and analyze a broad range of consequences of energy resource development in the western U.S. and to evaluate and compare alternative courses of action for dealing with the problems and issues either raised or likely to be raised by development of these resources.

The Project Director was Irvin L. (Jack) White, Assistant Director of S&PP and Professor of Political Science at the University of Oklahoma. White is now Special Assistant to Dr. Stephen J. Gage, EPA's Assistant Administrator for Research and Development. R. Leon Leonard, now a senior scientist with Radian Corporation in Austin, Texas, was a Co-Director of the research team, Associate Professor of Aeronautical, Mechanical, and Nuclear Engineering and a Research Fellow in S&PP at the University of Oklahoma. Leonard was responsible for editing and managing the production of this report. EPA Project Officer was Steven E. Plotkin, Office of Energy, Minerals and Industry, Office of Research and Development. Plotkin is now with the Office of Technology Assessment. Other S&PP team members are: Michael A. Chartock, Assistant Professor of Zoology and Research Fellow in S&PP and the other Co-Director of the team; Steven C. Ballard, Assistant Professor of Political Science and Research Fellow in S&PP; Edward J. Malecki, Assistant Professor of Geography and Research Fellow in S&PP; Edward B. Rappaport, Visiting Assistant Professor of Economics and Research Fellow in S&PP; Frank J. Calzonetti, Research Associate (Geography) in S&PP; Timothy A. Hall, Research Associate (Political Science); Gary D. Miller, Graduate Research Assistant (Civil Engineering and Environmental Sciences); and Mark S. Eckert, Graduate Research Assistant (Geography).

Chapters 3-7 were prepared by the Radian Corporation, Austin, Texas, under subcontract to the University of Oklahoma. In each of these chapters, Radian is primarily responsible for the description of the resource base and the technologies and S&PP is primarily responsible for the description of laws and regulations. The Program Manager at Radian was C. Patrick Bartosh. Clinton E. Burklin was responsible for preparation of these five chapters. Other contributors at Radian were: William R. Hearn, Gary D. Jones, William J. Moltz, and Patrick J. Murin.

Additional assistance in the preparation of the ERDS report was provided by Martha W. Gilliland, Executive Director, Energy Policies Studies, Inc., El Paso, Texas; Rodney K. Freed, Attorney, Shawnee, Oklahoma; and Robert W. Rycroft, Assistant Professor of Political Science, University of Denver, Denver, Colorado.

ABSTRACT

This report describes the technologies likely to be used for development of coal, oil shale, uranium, oil, natural gas, and geothermal resources in eight western states (Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming). It is part of a three-year "Technology Assessment of Western Energy Resource Development." The study examines the development of these energy resources in the eight states from the present to the year 2000. Other reports describe the analytic structure and conduct of the study, the impacts likely to result when these resources are developed, and analyze policy problems and issues likely to result from that development. The report is published in six volumes. Volume 1 describes the study, the technological activities such as exploration, extraction, and conversion for developing the resource, and laws and regulations which affect the development of more than one of the six resources considered in the study. The remaining five volumes are resource specific: Volume 2, Coal; Volume 3, Oil Shale; Volume 4, Uranium; Volume 5, Oil and Natural Gas; and Volume 6, Geothermal. Each of these volumes provides information on input materials and labor requirements, outputs, residuals, energy requirements, economic costs, and resource specific, state and federal laws and regulations.

OVERALL TABLE OF CONTENTS

FOR

THE ENERGY RESOURCE DEVELOPMENT SYSTEMS REPORT

VOLUME I: INTRODUCTION AND GENERAL SOCIAL CONTROLS		<u>PAGE</u>
Chapter 1	ENERGY RESOURCE DEVELOPMENT SYSTEMS	
1.1	Introduction.....	1
1.2	Objectives of the ERDS Document....	3
1.3	Organization of the ERDS Document..	4
1.4	Limitations of the ERDS Document...	9
Chapter 2	GENERAL SOCIAL CONTROLS	
2.1	Introduction.....	11
2.2	Environmental Impact Statements....	11
2.3	Siting and Land Use.....	19
2.4	Resource Exploration.....	29
2.5	Resource Acquisition.....	38
2.6	Resource Extraction.....	48
2.7	Occupational Safety and Health....	59
2.8	Air Quality.....	65
2.9	Water Quality.....	95
2.10	Water Use.....	109
2.11	Solid Waste Disposal.....	135
2.12	Noise Pollution.....	139
2.13	Transportation and Distribution....	145
2.14	Conclusions.....	153
VOLUME II: COAL		
Chapter 3	THE COAL RESOURCE DEVELOPMENT SYSTEM	
3.1	Introduction.....	1
3.2	Summary.....	3
3.3	Coal Resources.....	12
3.4	A Regional Overview.....	27
3.5	Exploration.....	37
3.6	Mining.....	52
3.7	Beneficiation.....	139
3.8	Conversion.....	174

OVERALL TABLE OF CONTENTS
(continued)

VOLUME III: OIL SHALE		<u>PAGE</u>
Chapter 4	THE OIL SHALE RESOURCE DEVELOPMENT SYSTEM	
4.1	Introduction.....	1
4.2	Summary.....	4
4.3	Resource Description.....	13
4.4	Exploration.....	25
4.5	Mining and Preparation.....	37
4.6	Processing.....	142
4.7	Land Reclamation.....	297
VOLUME IV: URANIUM		
Chapter 5	THE URANIUM RESOURCE SYSTEM	
5.1	Introduction.....	1
5.2	Uranium Resources.....	8
5.3	Exploration.....	31
5.4	Mining.....	64
5.5	Uranium Milling.....	197
VOLUME V: OIL AND NATURAL GAS		
Chapter 6	CRUDE OIL RESOURCE DEVELOPMENT SYSTEM	
6.1	Introduction.....	1
6.2	Resource Description of Western Crude Oil.....	8
6.3	Exploration.....	14
6.4	Crude Oil Production.....	57
6.5	Transportation.....	144
Chapter 7	THE NATURAL GAS RESOURCE DEVELOPMENT SYSTEM	
7.1	Introduction.....	146
7.2	Resource Description of the Western Natural Gas.....	151
7.3	Exploration.....	157
7.4	Natural Gas Production.....	165
7.5	Transportation.....	201

OVERALL TABLE OF CONTENTS
(continued)

VOLUME VI: GEOTHERMAL		<u>PAGE</u>
Chapter 8	THE GEOTHERMAL RESOURCE DEVELOPMENT SYSTEM	
8.1	Introduction.....	1
8.2	Summary.....	6
8.3	Resource Characteristics.....	13
8.4	Exploration.....	40
8.5	Extraction: Drilling.....	68
8.6	Extraction: Production.....	113
8.7	Uses of Geothermal Energy.....	146

TABLE OF CONTENTS
VOLUME III

CHAPTER 4: THE OIL SHALE RESOURCE DEVELOPMENT SYSTEM		<u>Page</u>
4.1	INTRODUCTION	1
4.2	SUMMARY	4
4.3	RESOURCE DESCRIPTION	13
	4.3.1 Resource Endowment	14
	4.3.2 Ownership of the Resources	23
4.4	EXPLORATION	25
	4.4.1 Technologies	25
	4.4.2 Input Requirements	27
	4.4.3 Outputs	30
	4.4.4 Social Controls	33
4.5	MINING AND PREPARATION	37
	4.5.1 Underground Mining	39
	4.5.1.1 Technologies	39
	4.5.1.2 Input Requirements	50
	4.5.1.3 Outputs	61
	4.5.2 Surface Mining	75
	4.5.2.1 Technologies	75
	4.5.2.2 Input Requirements	80
	4.5.2.3 Outputs	88
	4.5.3 Mining for In-Situ Processing	100
	4.5.3.1 Technologies	100
	4.5.3.2 Input Requirements	108
	4.5.3.3 Outputs	119
	4.5.4 Social Controls	127

TABLE OF CONTENTS (Continued)
VOLUME III

	<u>Page</u>
4.6	PROCESSING..... 142
4.6.1	Surface Processing..... 142
4.6.1.1	Technologies..... 143
4.6.1.2	Input Requirements..... 189
4.6.1.3	Outputs..... 211
4.6.2	In-Situ Processing..... 238
4.6.2.1	Technologies..... 238
4.6.2.2	Input Requirements..... 255
4.6.2.3	Outputs..... 265
4.6.3	Modified In-Situ Processing with Surface Processing of Mined Shale..... 278
4.6.3.1	Technology..... 278
4.6.3.2	Input Requirements..... 281
4.6.3.3	Outputs..... 284
4.6.4	Processing Social Controls..... 293
4.7	LAND RECLAMATION..... 297
4.7.1	Characteristics of Processed Shale..... 298
4.7.2	Disposal and Reclamation of Processed Shale.....:.. 300

LIST OF FIGURES
VOLUME III

CHAPTER 4: THE OIL SHALE RESOURCE DEVELOPMENT SYSTEM

<u>Number</u>		<u>Page</u>
4-1	Distribution of U.S. Oil Shale Resources.....	18
4-2	Oil Shale Areas in Colorado, Utah, and Wyoming....	20
4-3	Diagrammatic Cross-Section of Green River Formation.....	22
4-4	Oil Shale Development Schemes.....	38
4-5	Room-And-Pillar Mining.....	43
4-6	Shale Sizing Operations.....	48
4-7	Project Manpower Estimate.....	53
4-8	Hypothetical Open Pit Oil Shale Mine.....	78
4-9	Plan View of Retort Arrangement.....	101
4-10	Cross-Section of In-Situ Complex: Retort Operation and Development.....	103
4-11	An In-Situ Retort Being Developed By The Vertical Slot Development Method.....	105
4-12	An In-Situ Report Being Developed By The Multiple Level Development Method.....	105
4-13	Modified Sublevel Caving Method Proposed For Use in Rise Process.....	109
4-14	Manpower Projections.....	113
4-15	Classification of Retorting Methods.....	144
4-16	Pyrolysis and Oil Recovery Unit TOSCO II Process..	146
4-17	Flow Diagram of Institute of Gas Technology Oil Shale Process.....	153
4-18	Paraho Direct Mode Flow Diagram.....	158
4-19	Paraho Indirect Mode Flow Diagram.....	159
4-20	Union Retort B.....	164

LIST OF FIGURES (Continued)

VOLUME III

<u>Number</u>		<u>Page</u>
4-21	Union Retort B Flow Diagram.....	165
4-22	The Lurgi-Ruhrgas Process for the Retorting of Oil Shale.....	171
4-23	Cross-Section of Circular Grate Retort.....	178
4-24	Plan View of Circular Grate Retort Showing Movement of Charge through Various Zones.....	179
4-25	Upgrading and By-Product Recovery Facilities.....	186
4-26	Water System Flow Diagram of TOSCO II Oil Shale Process.....	202
4-27	Simplified Schematic of LERC True In-Situ Process.	243
4-28	Simplified Drawing of an Operating Retort.....	247
4-29	Flow Diagram of Oil Shale Processing Facility Featuring Modified In-Situ and Surface Retorting..	279

LIST OF TABLES
VOLUME III

CHAPTER 4: THE OIL SHALE RESOURCE DEVELOPMENT SYSTEM

<u>Number</u>		<u>Page</u>
4-1	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH THE EXPLORATION OF OIL SHALE IN THE WESTERN U.S..	5
4-2	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH AN UNDERGROUND MINE PRODUCING 66,000 TPD OF CRUSHED OIL SHALE.....	6
4-3	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A SURFACE MINE PRODUCING 66,000 TPD OF CRUSHED OIL SHALE.....	7
4-4	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A MINE EXCAVATING 41,000 TPD OF OIL SHALE FOR A MODIFIED IN-SITU DEVELOPMENT.....	8
4-5	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A SURFACE RETORTING/PROCESSING PLANT PRODUCING 50,000 BPD OF SHALE OIL PRODUCTS.....	9
4-6	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A MODIFIED IN-SITU PROCESSING PLANT PRODUCING 57,000 BPD OF SHALE OIL.....	11
4-7	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A MODIFIED IN-SITU AND SURFACE PROCESSING PLANT PRODUCING 76,000 BPD OF SHALE OIL.....	12
4-8	TYPICAL COMPOSITION OF OIL SHALE SECTIONS IN THE MAHOGANY ZONE OF COLORADO AND UTAH AVERAGING 25 GALLONS OF OIL PER TON.....	15
4-9	OIL SHALE RESOURCES OF THE U.S.....	16
4-10	LOCATION OF OIL SHALE RESOURCES.....	19
4-11	OIL SHALE RESOURCES IN THE GREEN RIVER FORMATION.	21
4-12	OWNERSHIP OF GREEN RIVER FORMATION OIL SHALE LANDS.....	24
4-13	OIL SHALE OWNERSHIP BY MAJOR OIL COMPANIES.....	24
4-14	ESTIMATED MANPOWER REQUIREMENTS FOR GEOLOGIC EXPLORATION TECHNIQUES.....	28

LIST OF TABLES (Continued)

VOLUME III

<u>Number</u>		<u>Page</u>
4-15	ESTIMATED MANPOWER COSTS FOR GEOLOGIC EXPLORATION TECHNIQUES.....	29
4-16	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH THE EXPLORATION OF OIL SHALE IN THE WESTERN U.S..	33
4-17	OIL SHALE EXPLORATION PERMIT FOR UTAH.....	36
4-18	MANPOWER REQUIREMENTS FOR ROOM-AND-PILLAR UNDERGROUND MINING.....	51
4-19	DESCRIPTION OF COMMERCIAL MINING EQUIPMENT.....	54
4-20	ESTIMATED EQUIPMENT LIST FOR UNDERGROUND MINING OF 66,000 TPD.....	55
4-21	CAPITAL COST ESTIMATES FOR AN UNDERGROUND SHALE MINE.....	57
4-22	ANNUALIZED OPERATING COSTS FOR AN UNDERGROUND SHALE MINE.....	59
4-23	SURFACE AREAS DISTURBED BY AN UNDERGROUND MINING DEVELOPMENT EXTRACTING 66,000 TPD.....	61
4-24	ANCILLARY ENERGY REQUIREMENTS FOR UNDERGROUND SHALE MINING.....	62
4-25	MINE VENT EMISSIONS, LB/HR FROM UNDERGROUND SHALE MINE EXCAVATING 66,000 TPD.....	64
4-26	PARTICULATE EMISSIONS FROM CRUSHING AND CONVEYING FOR AN UNDERGROUND SHALE MINE EXCAVATING 66,000 TPD	65
4-27	CONCENTRATIONS (MG/L) FOR DISSOLVED CONSTITUENTS IN GROUNDWATER IN THE PICEANCE CREEK BASIN.....	68
4-28	NOISE LEVELS ENCOUNTERED BY MINE WORKERS.....	71
4-29	POLYCYCLIC AROMATIC HYDROCARBONS DETECTED IN RAW OIL SHALE.....	73
4-30	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH AN UNDERGROUND MINE PRODUCING 66,000 TPD OF CRUSHED OIL SHALE.....	74

LIST OF TABLES (Continued)
VOLUME III

<u>Number</u>		<u>Page</u>
4-31	ESTIMATED EQUIPMENT LIST FOR A SURFACE MINE EXCAVATING 66,000 TPD OIL SHALE.....	83
4-32	UNIT ANNUALIZED COSTS FOR THE OPEN PIT MINING OF OIL SHALE.....	85
4-33	PRELIMINARY ANNUALIZED COSTS ESTIMATES FOR THE OPEN PIT MINING OF OIL SHALE.....	87
4-34	AVERAGE OF SURFACE DISTURBANCES ASSOCIATED WITH A 66,000 TPD SURFACE MINING OPERATION.....	89
4-35	ANCILLARY ENERGY REQUIREMENTS FOR SURFACE SHALE MINING AND CRUSHING.....	90
4-36	ATMOSPHERIC EMISSIONS FROM OIL SHALE SURFACE MINING.....	92
4-37	NOISE LEVELS ENCOUNTERED BY MINE WORKERS.....	98
4-38	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A SURFACE MINE PRODUCING 66,000 TPD OF CRUSHED OIL SHALE.....	99
4-39	MANPOWER REQUIREMENTS FOR IN-SITU MINING OPERATIONS.....	111
4-40	ESTIMATED EQUIPMENT LIST FOR MINING OF 41,000 TPD FROM IN-SITU OIL SHALE COMPLEX.....	115
4-41	MINING CAPITAL COST ESTIMATES FOR AN IN-SITU OIL SHALE COMPLEX.....	116
4-42	ANNUALIZED OPERATING COSTS FOR MINING AT AN IN-SITU OIL SHALE COMPLEX.....	118
4-43	ANCILLARY ENERGY REQUIREMENTS FOR MINING IN AN IN-SITU OIL SHALE FACILITY.....	120
4-44	MINE VENT EMISSIONS FROM MINING IN AN IN-SITU OIL SHALE FACILITY PRODUCING 57,000 BPD.....	122
4-45	PARTICULATE EMISSIONS FROM TRANSPORTATION AND DISPOSAL OF MINED-OUT SHALE.....	123
4-46	NOISE LEVELS ENCOUNTERED BY MINE WORKERS.....	126

LIST OF TABLES (Continued)
VOLUME III

<u>Number</u>		<u>Page</u>
4-47	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A MINE EXCAVATING 41,000 TPD OF OIL SHALE FOR A MODIFIED IN-SITU DEVELOPMENT.....	128
4-48	WYOMING OIL SHALE LEASE.....	136
4-49	UTAH OIL SHALE LEASE.....	136
4-50	SUMMARY OF PROPERTIES OF CRUDE SHALE OIL PRODUCED BY TOSCO II PROCESS.....	150
4-51	PROPERTIES OF CRUDE SHALE OIL PRODUCED BY TOSCO II PROCESS.....	151
4-52	TOSCO II SEMIWORKS PLANT COMPOSITION OF C ₄ AND LIGHTER GAS.....	152
4-53	PROPERTIES OF SHALE OIL OBTAINED FROM HYDRORETORTING IN IGT'S BENCH-SCALE UNIT.....	155
4-54	PROPERTIES OF PROCESSED SHALE RESIDUE OBTAINED FROM HYDRORETORTING IN IGT'S BENCH-SCALE UNIT....	155
4-55	PROPERTIES OF PARAHO SHALE OILS.....	162
4-56	COMPOSITION OF PARAHO RETORT GASES.....	163
4-57	PROPERTIES OF UNION RETORT B CRUDE OIL.....	169
4-58	CHARACTERISTICS OF OIL PRODUCTS OF THE LURGI-RUHRGAS RETORTING PROCESS.....	174
4-59	PROPERTIES OF DISTILLATION GAS FROM LURGI-RUHRGAS RETORTING PROCESS.....	175
4-60	PRODUCTS OF THE LURGI-RUHRGAS RETORTING PROCESS..	176
4-61	PRODUCTS FROM THE SUPERIOR MULTIMINERAL RECOVERY PROCESS.....	181
4-62	SUMMARY OF "ON-SITE" SHALE OIL UPGRADING BY SEVERAL OIL SHALE DEVELOPERS.....	184
4-63	MANPOWER REQUIREMENTS FOR 50,000 BPD TOSCO II SURFACE PROCESSING.....	191

LIST OF TABLES (Continued)
VOLUME III

<u>Number</u>		<u>Page</u>
4-64	CONSTRUCTION PHASE ESTIMATE OF CRAFT LABOR.....	193
4-65	PRODUCT AND INTERMEDIATE TANKAGE FOR A 50,000 BPD FACILITY.....	195
4-66	DETAILED EQUIPMENT LIST FOR A 100,000 BPD OIL SHALE RETORTING AND UPGRADING FACILITY.....	196
4-67	CAPITAL COST ESTIMATES FOR TOSCO II RETORTING AND UPGRADING FACILITIES.....	198
4-68	ANNUALIZED OPERATING COSTS FOR A 50,000 BPD TOSCO II PROCESSING FACILITY.....	200
4-69	USES OF WATER BY TOSCO II SHALE PROCESS PRODUCING 50,000 BPD SHALE OIL.....	203
4-70	WATER REQUIREMENTS OF A 50,000 BPD PARAHO SHALE OIL PLANT.....	205
4-71	SURFACE AREAS DISTURBED BY A TOSCO II PROCESS PRODUCING 50,000 BPD SHALE OIL.....	207
4-72	HEAT LOADS TO PROCESSING UNITS AT A TOSCO II FACILITY PRODUCING 50,000 BPD.....	209
4-73	SUMMARY OF AIR EMISSIONS FROM A TOSCO II PROCESSING FACILITY PRODUCING 50,000 BPD SHALE OIL PRODUCTS.....	212
4-74	ELEMENTAL CONCENTRATIONS IN TOSCO II SURFACE-RETORTED OIL SHALE.....	215
4-75	MINERAL CONSTITUENTS IN TYPICAL RETORTED OIL SHALES.....	216
4-76	POLYCYCLIC AROMATIC HYDROCARBONS DETECTED IN TOSCO II SURFACE-RETORTED SHALE.....	217
4-77	AIR EMISSIONS FROM THE PARAHO AND UNION B RETORTS	222
4-78	APPROXIMATE COMPOSITION OF TOSCO II COMBINED PROCESS WASTEWATER.....	224
4-79	ANALYSIS OF PARAHO PROCESS WASTEWATER.....	225

LIST OF TABLES (Continued)
VOLUME III

<u>Number</u>		<u>Page</u>
4-80	INORGANIC IONS LEACHABLE FROM FRESHLY RETORTED SHALES.....	227
4-81	MAJOR SOLID WASTES FROM A TOSCO II COMPLEX PRODUCING 50,000 BPD.....	229
4-82	POSSIBLE USES OF PROCESSED SHALE.....	231
4-83	COMPARABLE CARCINOGENIC POTENCY OF COMPLEX MIXTURES.....	234
4-84	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A SURFACE RETORTING/PROCESSING PLANT PRODUCING 50,000 BPD OF SHALE OIL PRODUCTS.....	236
4-85	PROPERTIES OF CRUDE SHALE OIL PRODUCED FROM THE OCCIDENTAL IN-SITU PROCESS.....	250
4-86	MANPOWER REQUIREMENTS FOR IN-SITU RETORTING AND PROCESSING OPERATIONS PRODUCING 57,000 BPD.....	257
4-87	CAPITAL COST ESTIMATES FOR AN IN-SITU OIL SHALE COMPLEX PRODUCING 57,000 BPD.....	260
4-88	ANNUALIZED OPERATING COSTS FOR AN IN-SITU OIL SHALE COMPLEX PRODUCING 57,000 BPD.....	262
4-89	SUMMARY OF WATER REQUIREMENTS FOR A MODIFIED IN-SITU FACILITY PRODUCING 57,000 BBL OF SHALE OIL PER DAY.....	264
4-90	ANCILLARY ENERGY REQUIREMENTS FOR AN IN-SITU OIL SHALE FACILITY PRODUCING 57,000 BPD.....	266
4-91	RETORTING/PROCESSING EMISSIONS FROM AN IN-SITU OIL SHALE COMPLEX, LB/HR.....	268
4-92	APPROXIMATE COMPOSITIONS OF FREE AND BOUND WATER CO-PRODUCED WITH SHALE OIL, MG/L.....	271
4-93	CHARACTERISTICS OF COOLING TOWER AND BOILER WATER BLOWDOWNS.....	273
4-94	NOISE LEVELS ENCOUNTERED BY NON-MINING PERSONNEL.	276

LIST OF TABLES (Continued)
VOLUME III

<u>Number</u>		<u>Page</u>
4-95	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A MODIFIED IN-SITU PROCESSING PLANT PRODUCING 57,000 BPD OF SHALE OIL.....	277
4-96	WATER BALANCE DURING NORMAL OPERATIONS OF COMBINED RETORTING FACILITIES.....	283
4-97	ELECTRIC POWER PRODUCTION AND CONSUMPTION FOR COMBINED RETORTING.....	285
4-98	ESTIMATED FUEL BALANCE FOR COMBINED RETORTING....	286
4-99	ESTIMATED EMISSIONS FROM COMBINED RETORTING DEVELOPMENT.....	288
4-100	NON-SHALE SOLID WASTES.....	291
4-101	SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A MODIFIED IN-SITU AND SURFACE PROCESSING PLANT PRODUCING 76,000 BPD OF SHALE OIL.....	292
4-102	NOISE POLLUTION CONTROL STANDARDS.....	296
4-103	PROPERTIES OF RETORTED SHALES.....	299

CONVERSION FACTORS

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
acre	m ²	4046.9
acre-ft/year	gpm	0.6200
acre-ft/year	m ³ /yr	1233.5
barrel	gal	42
barrel	m ³	0.1590
BPD	m ³ /s	1.84 x 10 ⁻⁶
Btu	joule	1054.4
Btu	cal	252
Btu/hour	watt	0.2931
Btu/pound	joule/gram	2.32
degrees API	specific gravity	- ^a
foot	m	0.3048
gallon	m ³	0.003785
gpm	m ³ /s	6.309 x 10 ⁻⁵
gpt	m ³ /metric ton	0.00416
grain/scf	gram/Nm ³	2.16
lb	kg	0.4536
lb/hr	kg/s	0.00756
psi	pascal	6894.8
SUS	centistokes	- ^b
ton	kg	907.18
TPD	metric ton/d	0.907

^a To convert from °API to specific gravity, divide 141.5 by the sum of 131.5 and the degrees API.

^b To convert from Saybolt Universal seconds, refer to tables (e.g., see CRC Handbook of Chemistry and Physics, 54th Edition, p. F-43) or approximate equations (e.g., see Chemical Engineers' Handbook, Perry and Chilton, eds., 5th Edition, p. I-27).

ACKNOWLEDGEMENTS

Patrick J. Murin of the Radian Corporation had primary responsibility for preparation of this volume of the Energy Resource Development Systems (ERDS) Report. The social controls sections were prepared by Rodney K. Freed of the Science and Public Policy Program at the University of Oklahoma. Mr. Freed is now an attorney in Shawnee, Oklahoma.

The research reported here could not have been completed without the assistance of a dedicated administrative support staff. At Radian Corporation, Mary Harris was responsible for typing of this volume, and at the University of Oklahoma, Janice Whinery, Assistant to the Director, coordinated assembly of the volumes of the ERDS Report.

Nancy Ballard, graphics arts consultant, designed the title page.

Steven E. Plotkin, EPA Project Officer, has provided continuing support and assistance in the preparation of this report.

The individuals listed below participated in the review of this volume of the ERDS Report and provided information for its preparation. Although these critiques were extremely helpful, none of these individuals is responsible for the content of this volume. This volume is the sole responsibility of the Science and Public Policy interdisciplinary research team and the Radian Corporation.

Dr. John Hoover
Energy and Environmental
Systems
Argonne National Laboratory
Chicago, Illinois

Mr. R.D. Kerr
Laramie Energy Research Center
Department of Energy
Laramie, Wyoming

Mr. Lionel S. Johns
Program Manager
Office of Technology Assessment
U.S. Congress
Washington, D.C.

Dr. Charles H. Prien
Senior Research Fellow
Chemical Division
Denver Research Institute
Denver, Colorado

CHAPTER 4

THE OIL SHALE RESOURCE DEVELOPMENT SYSTEM

4.1 INTRODUCTION

This document is one of several reports issued in support of a "Technology Assessment of Western Energy Resource Development," a project jointly conducted by the Science and Public Policy Program of the University of Oklahoma and the Radian Corporation of Austin, Texas. The project is funded by the Office of Energy, Minerals, and Industry, Office of Research and Development, Environmental Protection Agency under Contract 68-01-1916. The "Technology Assessment of Western Energy Resource Development" describes the development of energy resources in eight western states. These states are: Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming.

This document is issued as Chapter 4 of the "energy resource development system" (ERDS) report. For each of six energy resources, the ERDS report describes the energy resource base, the technologies used to develop the resource, the inputs and outputs for each development technology, and the laws and regulations applying to the deployment and operation of each technology. Resources described in the ERDS report are: coal, oil shale, uranium, oil, natural gas, and geothermal energy.

This chapter describes the technologies, inputs, outputs, laws, and regulations associated with the development of oil shale resources. The chapter comprises five major sections which begin with a general description of the oil shale resource. The remaining sections describe the steps or activities involved in developing oil shale resources.

Section 4.2 summarizes the input requirements and outputs identified in this study as resulting from the development and utilization of the western oil shale resource.

Section 4.3, Resource Description, describes the characteristics of the oil shale resource and gives estimates of total resources and reserves. Section 4.3 also discusses the oil shale resource in terms of location and ownership.

The remaining sections describe the development of the oil shale resource as a basic sequence of "activities". In the development of the oil shale resource, these activities include exploration, mining, processing, and reclamation. For each activity, "technological alternatives" are discussed which represent potential development options (e.g., shale can be mined on the surface or mined underground). When available, input requirements and outputs for each technological alternative or activity are presented. Input requirements discussed in this report include: manpower, materials and equipment, economics, water, land, and ancillary energy. The outputs include the residuals that may pose environmental hazards such as: air emissions, water effluents, solid wastes, noise pollution, occupational health and safety hazards, and odors.

Section 4.4 discusses the technologies, inputs, outputs, laws, and regulations associated with oil shale exploration. Section 4.5 discusses the same items for the mining and preparation of oil shale, including discussions of underground mining, surface mining, and mining for "in-situ" processing. Section 4.6 describes oil shale processing, including discussions of surface and in-situ processing. Section 4.7 is a brief description of the reclamation of processed shale.

The report is largely based on development plans and environmental impact statements prepared by oil shale developers. Certain inputs and outputs have not been defined by developers (e.g., materials and equipment requirements and operating costs). Estimates of these inputs and outputs are presented, but the reader should recognize that large discrepancies are possible.

Inputs and outputs describing surface oil shale processing are mainly derived from published development plans featuring the TOSCO II retorting process. Data for other surface processing technologies are mostly unavailable. However, limited data for these other surface processes are presented in this report.

Data describing modified in-situ processing are derived from published development plans for the Occidental process. Other data are provided from development plans featuring both a modified in-situ process (the RISE process) and a surface retorting process (the TOSCO II process).

Two principal options are available for producing marketable shale oil. One is to minimize upgrading and market the raw shale oil as a synthetic heavy crude oil or No. 6 fuel oil. The second option is to upgrade or pre-refine shale oil on-site. In this report, data describing the TOSCO II surface retorting process include significant upgrading on-site to produce a low-sulfur oil, liquefied petroleum gas, and coke. Data describing the in-situ process developments include only those upgrading steps needed to yield a crude shale oil that can be pipelined to a refinery.

4.2 SUMMARY

The input requirements and outputs associated with each step of the oil shale resource development system are summarized in Tables 4-1 through 4-7. The input requirements include manpower, materials and equipment, economics, water, land, and ancillary energy. The outputs include air, water, and solid waste emissions, noise, odors, and occupational health and safety hazards.

These summary tables present typical values for various oil shale development options. The inputs and outputs are based on little experience and should be interpreted only as preliminary estimates. The assumptions used to develop these tables are described in detail in their respective sections of the text.

TABLE 4-1. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED
WITH THE EXPLORATION OF OIL SHALE
IN THE WESTERN U.S.

Inputs

Manpower	
• geological activities	10 man-years
• drilling activities	1.5 man-years
Materials and Equipment	
• vehicles	Supplied by contractor
• drilling rigs	
• well logging	
Economics ^a	
• geological activities	\$400,000
• drilling activities	\$200,000
Water	Negligible
Land	Temporary and negligible
Ancillary Energy	Minor

Outputs

Air Emissions	Minor
Water Effluents	Minor
Solid Wastes	Minor
Noise	Temporary
Occupational Health and Safety	Negligible
Odors	Temporary and negligible

^a1977 dollars

TABLE 4-2. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED
WITH AN UNDERGROUND MINE PRODUCING
66,000 TPD OF CRUSHED OIL SHALE

Inputs

Manpower	
• operating	743 men
Materials and Equipment	
• jumbo drills	9
• powder trucks	5
• scaling and roof bolting rigs	5
• front end loaders	7
• haulage trucks	20
• bulldozers	10
• steel	7300 tons
Economics ^a	
• capital	\$190,000,000
• annualized operating	\$74,000,000
Water	600 gpm
Land	300-500 acres
Ancillary Energy	
• electricity	6.2 x 10 ⁸ kwh/yr
• diesel fuel ^b	10,000 gal/yr

Outputs

Air Emissions	
• particulates	125 lb/hr
• hydrocarbons	54 lb/hr
• NO _x	270 lb/hr
• CO	480 lb/hr
• SO ₂	Negligible
• CO ₂	9000 lb/hr
Water Effluents	Extremely site dependent
Solid Wastes	
• from opening mine	150,000 tons
• other	Returned to mine
Noise Pollution	
• at mine boundary	Negligible
Occupational Health and Safety	
• deaths	0.8/yr
• injuries	34/yr
Odors	Confined to mine site

^a1977 dollars

^bMay be supplied by upgraded shale oil

TABLE 4-3. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED
WITH A SURFACE MINE PRODUCING
66,000 TPD OF CRUSHED OIL SHALE

Inputs

Manpower	
• operating	410 men
Materials and Equipment	
• loading shovels	4
• trucks	12
• drills	4
• bulldozers	3
• front-end loaders	2
• explosives truck	1
• steel	7400 tons
Economics ^a	
• capital	Over \$200,000,000
• annualized operating	\$61,000,000
Water	600 gpm
Land	800-1200 acres
Ancillary Energy	
• electricity	2.7×10^8 kwh/yr
• diesel fuel ^b	22,000 gal/d

Outputs

Air Emissions	
• particulates	510 lb/hr
• hydrocarbons	92 lb/hr
• NO _x	800 lb/hr
• CO	480 lb/hr
• SO ₂	59 lb/hr
• CO ₂	19,000 lb/hr
Water Effluents	Extremely site dependent
Solid Wastes	
• overburden	71,000 TPD
Noise	
• at mine boundary	Negligible
Occupational Health and Safety	
• deaths	0.2/yr
• injuries	10/yr
Odors	Confined to mine site

^a1977 dollars

^bMay be supplied by upgraded shale oil

TABLE 4-4. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED
WITH A MINE EXCAVATING 41,000 TPD OF OIL
SHALE FOR A MODIFIED IN-SITU DEVELOPMENT

<u>Inputs</u>	
Manpower	
• operating	1039 men
Materials and Equipment	
• jumbo drills	6
• powder trucks	4
• scaling and roof bolting rigs	4
• front-end loaders	4
• haulage trucks	12
• bulldozers	4
Economics ^a	
• capital	\$140,000,000
• annualized operating	\$56,000,000
Water	450 gpm
Land	
• mine shafts, support structures, roads	100 acres
• mined-out shale	100 acres/yr
Ancillary Energy	
• electricity	2.3 x 10 ⁸ kwh/yr
• diesel fuel	7000 gal/d
<u>Outputs</u>	
Air Emissions	
• particulates	382 lb/hr
• hydrocarbons	12 lb/hr
• NO _x	300 lb/hr
• CO	260 lb/hr
• SO ₂	2 lb/hr
• CO ₂	6200 lb/hr
Water Effluents	Extremely site dependent
Solid Wastes	
• raw shale	41,000 TPD
Noise Pollution	
• at mine boundary	Negligible
Occupational Health and Safety	
• deaths	0.5/yr
• injuries	21/yr
Odors	Confined to mine site

^a1977 dollars

TABLE 4-5. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH
A SURFACE RETORTING/PROCESSING PLANT PRODUCING
50,000 BPD OF SHALE OIL PRODUCTS^a

Inputs

Manpower	
• operating	429 men
• peak construction ^b	3300 men
Materials and Equipment	
• pyrolysis and oil recovery units	
• gas recovery and treating units	
• hydrogen production units	
• gas-oil and naphtha hydrogenation units	
• ammonia separation and sulfur recovery units	
• delayed coker	
• foul water stripping units	
• cement	9000 tons
• structural steel	6000 tons
• reinforcing bars and piping	2000 tons
• valves	2000
Economics ^c	
• capital	\$827,000,000
• annualized operating	\$126,000,000
Water	
• TOSCO II	5030 gpm
• Paraho ^d	3130-4150 gpm
• Union B ^d	2600 gpm
• Lurgi-Ruhrgas ^d	1470 gpm
• Superior ^d	3500 gpm
Land	1200-1500 acres
Ancillary Energy	
• TOSCO II	7×10^8 kwh/yr
• Paraho ^d	4.5×10^8 kwh/yr
• Union B ^d	6×10^8 kwh/yr
• Lurgi-Ruhrgas ^d	3×10^8 kwh/yr

(Continued)

TABLE 4-5. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH
A SURFACE RETORTING/PROCESSING PLANT PRODUCING
50,000 BPD OF SHALE OIL PRODUCTS^a (Continued)

Outputs

Air Emissions ^e	
• particulates	720-860 lb/hr
• hydrocarbons	950-1000 lb/hr
• NO _x	1630-1900 lb/hr
• CO	60-80 lb/hr
• SO ₂	270-350 lb/hr
• CO ₂	580,000 lb/hr
Water Effluents	No direct discharge
Solid Wastes	
• TOSCO II processed shale	53,000 TPD
• catalysts, sludges, etc.	1800 TPD
Noise Pollution	
• at plant boundaries	Negligible
Occupational Health and Safety	
• deaths	0.15/yr
• injuries	15/yr
• man-days lost	15/yr
Odors	Confined to plant site

^aInputs and outputs are based primarily on the TOSCO II process. When possible, inputs/outputs for other surface retorting technologies are presented. The plant produces a full range of products, as discussed in the text.

^bPeak for all phases (including mine construction)

^c1977 dollars

^dWater and energy requirements for Paraho, Union B, Lurgi-Ruhrgas, and Superior processes describe complexes with less extensive processing of the product shale oil than specified by TOSCO II developers. Please see the appropriate sections in the text for a discussion of these differences.

^eThese air emissions describe the TOSCO II processing complex; estimates for emissions from the Union B and Paraho retorts only are found in the text.

TABLE 4-6. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH
A MODIFIED IN-SITU PROCESSING PLANT PRODUCING
57,000 BPD OF SHALE OIL

Inputs

Manpower	
• operating	561 men
• peak construction ^a	2900 men
Materials and Equipment	
• gas and water treatment units	
• oil/water separators	
• product gas boilers	
Economics ^b	
• capital	\$306,000,000
• annualized operating	\$76,000,000
Water	2500 gpm
Land	80 acres
Ancillary Energy ^c	6.7×10^8 kwh/yr

Outputs

Air Emissions	
• particulates	74 lb/hr
• hydrocarbons	120 lb/hr
• NO _x	588 lb/hr
• CO	84 lb/hr
• SO ₂	174 lb/hr
• CO ₂	2,400,000 lb/hr
Water Effluents	No direct discharge
Solid Wastes	Minor
Noise Pollution	
• at plant boundaries	Negligible
Occupational Health and Safety	Unknown
Odors	
• at plant boundaries	Negligible

^aPeak for all phases (including mine construction)

^b1977 dollars

^cPotentially supplied on-site

TABLE 4-7. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A
MODIFIED IN-SITU AND SURFACE PROCESSING PLANT
PRODUCING 76,000 BPD OF SHALE OIL

<u>Inputs</u>		
Manpower		
• operating		1000
• peak construction ^a		2500
Materials and Equipment		
• TOSCO II retorts		
• oil and oil-gas recovery units		
• gas purification and sulfur recovery units		
• foul water stripper		
• oil fractionation and high Btu gas units		
• oil upgrading and blending units		
Economics		Unknown
Water		2750 gpm
Land		
• surface processing facilities		240 acres
• shale disposal (over 30 years)		900 acres
• corridors (including mine)		280 acres
Ancillary Energy		3.2 x 10 ⁸ kwh/yr
<u>Outputs</u>		
Air Emissions		
• particulates		483 lb/hr
• hydrocarbons		174 lb/hr
• NO _x		2370 lb/hr
• CO		--
• SO ₂		458 lb/hr
• CO ₂		2,250,000 lb/hr
Water Effluents		No direct discharge
Solid Wastes		
• processed shale		36,000 TPD
• catalysts and sludges		820 TPY
Noise Pollution		
• at plant boundaries		Negligible
Occupational Health and Safety		Unknown
Odors		
• at plant boundaries		Negligible

^aPeak for all phases (including mine construction)

4.3 RESOURCE DESCRIPTION

Oil shale is a marlstone-type inorganic material containing organic matter known as kerogen. Kerogen is only slightly soluble in conventional organic solvents. When the shale is heated to about 900°F, the kerogen decomposes to yield hydrocarbon gases and liquids. These hydrocarbon products can be refined and processed in much the same manner as petroleum. Deposits of oil shale are usually found in a layer or series of layers, known as a "zone," sandwiched between other layers of sedimentary rock.

Oil shale resources can be described by determining the average oil yields obtainable by heating the shale. A standardized laboratory technique called a Fischer Assay is commonly used to evaluate the oil shale yield. High-grade shale is normally defined as a deposit that averages 30 or more gallons of oil per ton of shale. Shale with an average yield of less than 10 gallons per ton is normally omitted from U.S. Geological Survey resource estimates. Since an oil shale zone is often composed of a large number of thin layers with different yields, a zone average may be composed of widely varying yields.

In addition to yield, several other factors are significant in determining the desirability for recovering hydrocarbon products from an oil shale deposit. These include zone thickness, overburden thickness, and the presence of other valuable materials in the shale. In practice, the minimum zone thickness considered for recovery is ten to fifteen feet. Many high-quality deposits are known to be well over 100 feet thick.

The amount of overburden determines the economic feasibility of both surface and underground mining of oil shale. As with

coal, the largest amount of overburden that can be economically removed to recover oil shale is determined by the thickness of the target shale zone. Most high quality oil shale lies below a thick overburden containing little or no kerogen. There are some areas, however, where oil shale lies close enough to the surface to permit surface mining.

The presence of materials in the shale other than kerogen is of interest when the materials might themselves be recoverable and marketable. Some of the western oil shales are known to contain nahcolite (sodium bicarbonate), trona (sodium sesquicarbonate), soda ash (sodium carbonate), halite (sodium chloride), dawsonite (alumina), and others. Eastern deposits contain small amounts of phosphate and metals such as uranium and vanadium. Typical organic and mineral contents for an oil shale containing 25 gallons of oil per ton of shale are given in Table 4-8.

4.3.1 Resource Endowment

Table 4-9 contains estimates of the total oil shale resources of the United States. These and other estimates are highly uncertain. The estimates have been classed into several categories based upon the reliability of the estimate and quality of the shale. The U.S. Geological Survey (USGS) identified oil shale deposits containing more than two trillion barrels of oil. The USGS also estimated that as yet undiscovered deposits may contain an additional 25 trillion barrels. Although no oil shale was previously regarded as recoverable by the USGS, 418 billion barrels were thought to border on being economically producible or were not producible solely because of legal or political circumstances. The portion of the 418 billion barrels that can be classified as "reserves"

TABLE 4-8. TYPICAL COMPOSITION OF OIL SHALE SECTIONS
IN THE MAHOGANY ZONE OF COLORADO AND UTAH
AVERAGING 25 GALLONS OF OIL PER TON

		Weight-Percent
Organic Matter:		
Content of raw shale	<u>13.8</u>	
Ultimate composition:		
Carbon		80.5
Hydrogen		10.3
Nitrogen		2.4
Sulfur		1.0
Oxygen		<u>5.8</u>
Total		100.0
Mineral Matter:		
Content of raw shale	<u>86.2</u>	
Estimated mineral constituents:		
Carbonates, principally dolomite		48.0
Feldspars		21.0
Quartz		13.0
Clays, principally illite		13.0
Analcite		4.0
Pyrite		<u>1.0</u>
Total	100.0	100.0

Reference: U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program, 6 vols, Washington, D.C., 1973.

TABLE 4-9. OIL SHALE RESOURCES OF THE U.S.^a
(BILLIONS OF BARRELS OF OIL YIELD)

Feasibility of Recovery	Knowledge of Resource		
	Identified ^b	Undiscovered ^c	
		Hypothetical ^d	Speculative ^e
Recoverable	0	0	0
Paramarginal ^f	418	300	600
Submarginal ^g	1,600	1,600	23,000

^aReliability of estimate decreases downward and to the right.

^bSpecific bodies known from geological evidence supported by engineering measurements.

^cUnspecified bodies of mineral-lease material surmised to exist on the basis of broad geologic knowledge and theory.

^dUndiscovered materials that may reasonably be expected to exist in a known mining district.

^eUndiscovered materials that may occur either in known types of deposits in a favorable geologic setting where no discoveries are made or in as yet unknown types of deposits that remain to be recognized.

^fThat portion of subeconomic resources that (1) borders on being economically producible or (2) is not commercially available solely because of legal or political circumstances.

^gThe portion of subeconomic resources which would require a substantially higher price (more than 1.5 times the price at the time of determination) or a major cost-reducing advance in technology.

Sources: Culbertson, William C., and Janet K. Pitman. "Oil Shale." In: D. A. Brobst and W. P. Pratt (eds.) United States Mineral Resources, U.S. Geological Survey Professional Paper 820, Washington, D.C.: Government Printing Office, 1973, pp. 495-503.

Duncan, D. C., and V. E. Swanson. Organic-Rich Shale of the United States and World Land Areas, U.S. Geological Survey Circular 523, Washington, D.C.: Government Printing Office, 1965.

(i.e., both known to exist and economically recoverable using currently available technologies) depends on assumptions about the costs of alternate energy sources. The U.S. Department of the Interior estimated that 80 billion barrels of oil were actually recoverable under 1973 conditions.¹ The National Petroleum Council estimated that 129 billion barrels were recoverable under 1972 conditions.² By either of these estimates, oil shale reserves contain more energy than the total U.S. reserves of oil and natural gas. The reserve estimates can also be compared to the U.S. consumption of about six billion barrels of crude oil in 1976.

About 90 percent of the identified oil shale resources of the U.S. are located in a single geological formation in western Colorado, Utah, and Wyoming known as the Green River Formation (Figure 4-1 and Table 4-10). Other oil shales underlie large areas in the eastern and central parts of the 48 contiguous states and the northern part of Alaska.

The Green River Formation underlies 25,000 square miles of land, some 17,000 of which are believed to contain oil shale deposits with commercial development potential. These deposits occur in several geologic basins (Figure 4-2) and, in many instances, are exposed at the basin edges but slant deeply underground toward the centers of the deposits. Although substantial deposits are found in all three states, about 80 percent of the higher grade zones are in Colorado, mostly in the Piceance Basin (Table 4-11). Figure 4-3 is a schematic

¹U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program, 6 vols., Washington, D.C., Government Printing Office, 1973.

²National Petroleum Council. U.S. Energy Outlook, A report of the National Petroleum Council's Committee on U.S. Energy Outlook, Washington, D.C., 1972.

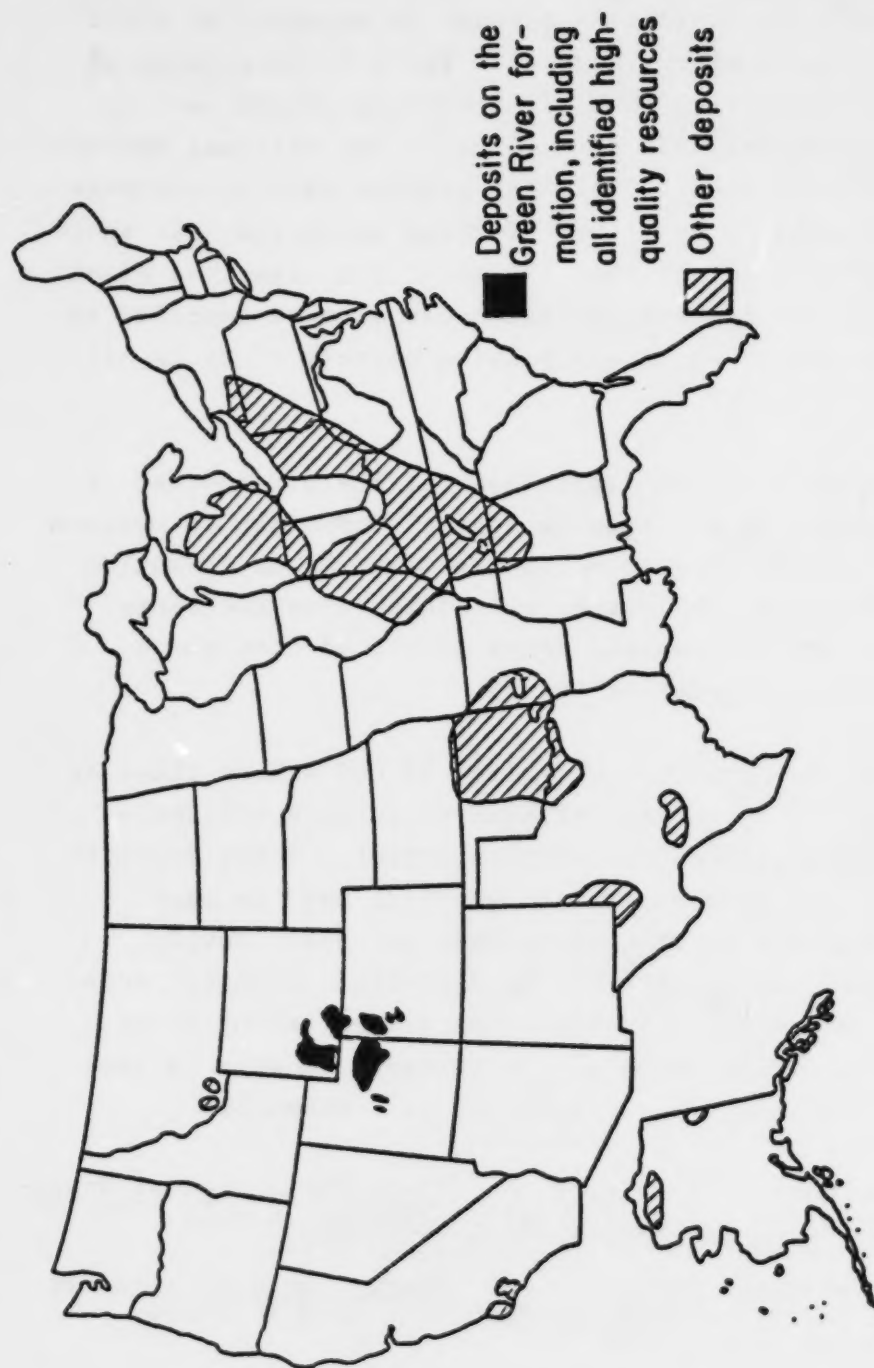


Figure 4-1. Distribution of U.S. Oil Shale Resources.

Source: Duncan, D. C., and V. E. Swanson. Organic-Rich Shale of the United States and World Land Areas, U.S. Geological Survey Circular 523, Washington, D.C., Government Printing Office, 1965.

TABLE 4-10. LOCATION OF OIL SHALE RESOURCES^a
(BILLIONS OF BARRELS OIL YIELD)

Location	Identified			Hypothetical			Speculative		
	25-100 Gallons per Ton	10-25 Gallons per Ton	10-25 Gallons per Ton	25-100 Gallons per Ton	10-25 Gallons per Ton	10-25 Gallons per Ton	25-100 Gallons per Ton	10-25 Gallons per Ton	10-25 Gallons per Ton
Green River Formation (Colorado, Utah, and Wyoming)	418	1,400		50	600		0	0	0
Chattanooga shale and equivalent formations (Central and Eastern U.S.)	0	200		0	800		0	0	0
Marine shale (Alaska)	small	small		250	200		0	0	0
Other shale deposits	0	small		NE	NE		600	23,000	
TOTAL	>418	>1,600		300	1,600		600	23,000	

NE = not estimated.

^aFor definition of categories, see Table 4-9.

Source: Culbertson, William C., and Janet K. Pitman. "Oil Shale". In: D. A. Brobst and W. P. Pratt (eds.) United States Mineral Resources, U.S. Geological Survey Professional Paper 820, Washington, D.C.: Government Printing Office, 1973, pp. 495-503.

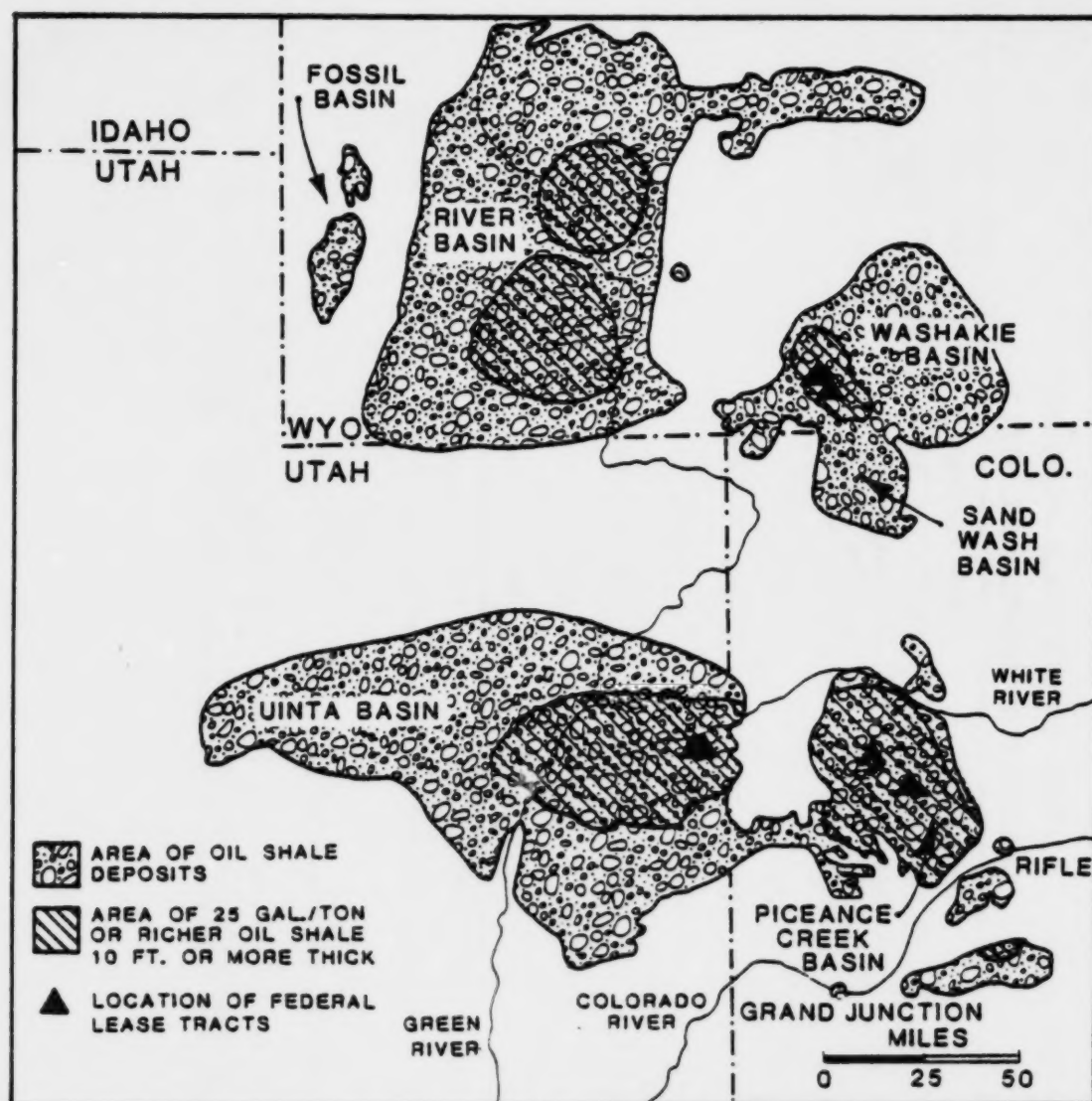


Figure 4-2. Oil Shale Areas in Colorado, Utah, and Wyoming.

Source: U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program, 6 vols., Washington, D.C., Government Printing Office, 1973.

TABLE 4-11. OIL SHALE RESOURCES IN THE GREEN RIVER FORMATION
(BILLIONS OF BARRELS)

Location	Resource Class ^a				Total
	Class 1	Class 2	Class 3	Class 4	
Piceance Basin Colorado	34	83	167	916	1,200
Unita Basin Colorado and Utah	0	12	15	294	321
Wyoming	0	0	4	256	260
Total	34	95	186	1,466	1,781

^aClasses 1,2: Resources satisfying a basic assumption limiting resources to deposits at least 30 feet thick and averaging 30 gallons of oil per ton of shale, by assay. Only the most accessible and better defined deposits are included. Class 1 indicates the portion of these resources which would average 35 gallons per ton over a continuous interval of at least 30 feet.

Class 3: Although matching Classes 1 and 2 in richness, more poorly defined and not as favorably located.

Class 4: Lower grade, poorly defined deposits ranging down to 15 gallons per ton.

Source: National Petroleum Council. U.S. Energy Outlook, A report of the National Petroleum Councils Committee on U.S. Energy Outlook, Washington, D.C., 1972, pp. 207-208.

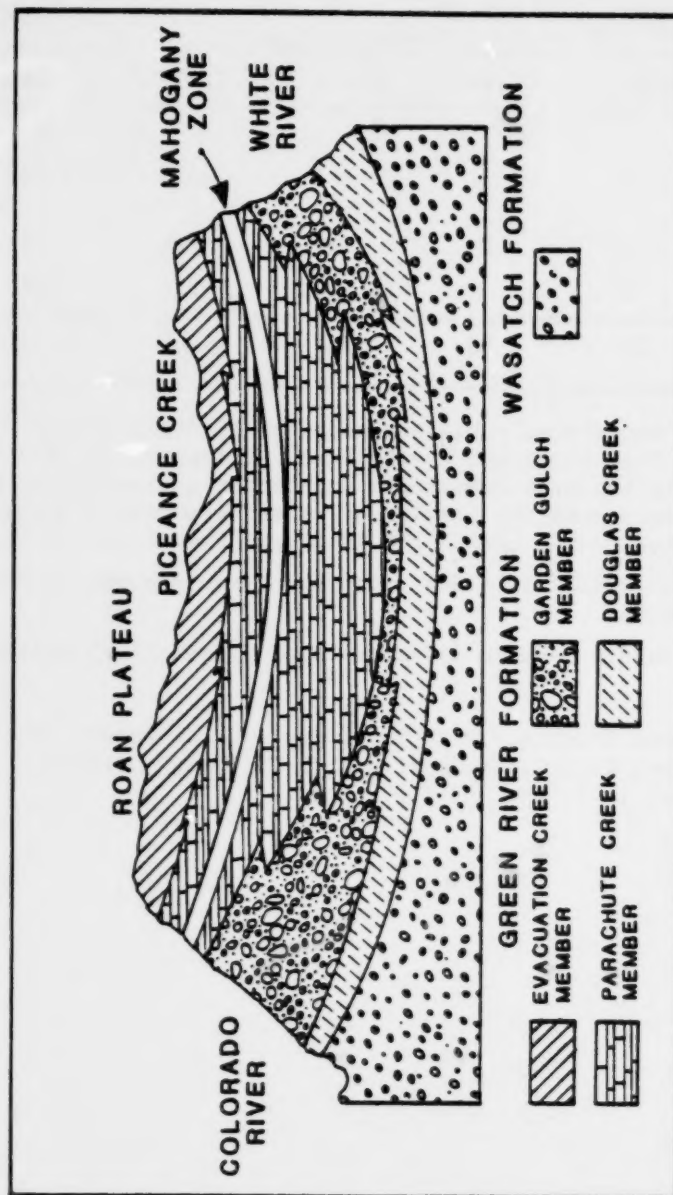


Figure 4-3. Diagrammatic Cross-Section of Green River Formation.

Source: Atwood, Mark T. "The Production of Shale Oil," Chemtech, October 1973, p. 619.

cross-section of the Green River Formation as it occurs in the Piceance Basin.

"About 84% of the known high grade reserves (25 gal/ton or greater) are located in Colorado, 10% in Utah and 6% in Wyoming. Even though Colorado has the smallest geographical area of oil shale, it has the richest, thickest and best defined deposits. It is likely that oil shale development will be, therefore, greatest in Colorado."¹

4.3.2 Ownership of the Resources

About 80 percent of the high-grade shale lands in the Green River Formation are owned by the federal government.² Private lands extend almost uninterrupted along the southern margin of the Piceance Basin, but federal ownership predominates elsewhere. The title to much of the federal land is under challenge on the basis of unpatented mining claims not yet litigated (Table 4-12). As of 1973 about 85 percent of the federal oil shale land had a clouded title, including 95 percent of the lands in the rich Piceance Creek Basin. Although many claims have been cleared, no recent estimates of the amount of land cleared are available. More than 75 percent of the private acreage is controlled by seven firms (Table 4-13).³

¹Federal Energy Administration, Interagency Task Force on Oil Shale. Project Independence Blueprint, Final Task Force Report, Potential Future Role of Oil Shale Prospects and Constraints, November, 1974.

²House Committee on Science and Astronautics, Subcommittee on Energy. Energy from Oil Shale: Technical, Environmental, Economic, Legislative, and Policy Aspects of an Undeveloped Energy Source, Washington, D.C., Government Printing Office, 1973.

³Federal Energy Administration, Interagency Task Force on Oil Shale, *op.cit.*, p. 100.

TABLE 4-12. OWNERSHIP OF GREEN RIVER FORMATION OIL SHALE LANDS
(THOUSANDS OF ACRES)

Ownership	Colorado	Utah	Wyoming	Total
Federal oil shale land (clear title)	320	780	70	1,170
Federal oil shale land (clouded title)	1,100	3,000	2,600	6,700
Nonfederal oil shale lands including Indian and state lands	380	1,120	1,630	3,130
Total	1,800	4,900	4,300	11,000

Source: U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program, 6 vols., Washington, D.C., Government Printing Office, 1973, Vol. I, pp. II-104 - II-106.

TABLE 4-13. OIL SHALE OWNERSHIP BY MAJOR OIL COMPANIES

Companies	Colorado		Utah		Total	
	Acres	Tracts*	Acres	Tracts	Acres	Tracts
Standard of California	40,950	4	0	0	40,950	4
Union Oil	29,630	3	0	0	29,630	3
Texaco	19,170	3	8,300	1	27,470	4
Getty	24,300	1	0	0	24,300	1
Atlantic Richfield	19,730	13	2,570	1	22,300	14
Mobil	19,280	2	0	0	19,280	2
Sohio	9,620	12	8,970	5	18,590	17

*Number of noncontiguous tracts.

Source: Federal Energy Administration, Interagency Task Force on Oil Shale. Independence Blueprint, Final Task Force Report, Potential Future Role of Oil Shale Prospects and Constraints, November 1974, p. 101.

4.4 EXPLORATION

The location and distribution of oil shale deposits in the Green River Formation have been thoroughly documented. Future exploration efforts will emphasize defining known deposits to find those most suitable for a particular mining/processing scheme rather than locating new deposits.

4.4.1 Technologies

A typical exploration strategy for defining oil shale deposits for a proposed recovery operation consists of the following steps:

1. Review of existing data and outlining of potential areas,
2. Field work for evaluation of the areas, followed by a preliminary report,
3. Organization and conduct of a drilling program to define the rock mechanics of the target shale deposit, and
4. Interpretation of results, formulation of recommendations, and final report writing.

Two different but related technologies are used in exploration: geologic techniques and drilling. Borehole geophysics are also usually applied with a drilling program. A team of geologists and support personnel are required to conduct the geologic studies. A drilling crew is required to operate equipment during the drilling program.

The geologic techniques serve as the backbone of the exploration effort, including the organization and direction of the drilling program. The specific geologic methods used are primarily surface and subsurface mapping of geologic parameters significant to the occurrence of oil shale.

The target area of most oil shale exploration is much smaller than for many other energy resources such as coal or crude oil. A review of existing data should delineate deposits having the proper ranges of kerogen content, oil shale thickness, and overburden thickness. Field work may then be needed to confirm the results of the office study. This field work typically comprises surface study of outcrops and geologic mapping. The information gathered during the review of existing data and the field work serves as the basis for initiating the drilling program. Geophysical methods, such as seismic surveys, may be used to supplement the surface geological studies, but they are not likely to be cost-effective since the structural geology of the deposits is already well known.

Drilling is required to define the rock mechanics of the target shale deposit. Data gathered during drilling is used to define the suitability of a shale deposit to a particular mining/processing scheme. These data are subsequently used in the design of the shale mine (or other recovery method).

Two drilling methods - the conventional rotary and the coring methods - will likely be used in the drilling phase of the exploration program. The coring method uses mud or water circulation exclusively, but the conventional rotary method may use either liquid or air circulation. Borehole geophysical logs (electric logs, gamma-ray logs, and acoustic logs) are usually run after the borehole is completed. Because the grade (kerogen

content) of oil shale is of utmost importance in determining the value of oil shale, and because the grade may vary laterally over short distances, a relatively intense drilling effort is required.

4.4.2 Input Requirements

As a basis for the input requirements and outputs, the target of exploration is assumed to be a shale deposit that can support the operation of a 50,000 barrel-per-day processing facility for 30 years. The total oil required from the shale amounts to about 550 million barrels.

The magnitude of the exploratory effort can be estimated with data from the Gulf-Standard core-hole program for federal oil shale tract C-a. In defining a tract comprising 8 square miles, Gulf-Standard initiated the drilling of 13 core holes in addition to 12 previously drilled on the tract.¹ Drilling efforts required to define the target shale deposit are thus assumed to be the drilling of 25 core holes.

4.4.2a Manpower

Professional geologists and support personnel are required at all stages of the oil shale exploration. Table 4-14 presents a gross estimate of the manpower requirements for the application of geologic techniques in the various stages of the hypothetical exploration effort. For this analysis, a team of two geologists and three support personnel is assumed.

¹Gulf Oil Corporation and Standard Oil Company. Detailed Development Plan for Tract C-a. Volume 2. Prepared for Area Oil Shale Supervisor. March 1976. pp. 3-3-7 to 3-3-8.

TABLE 4-14. ESTIMATED MANPOWER REQUIREMENTS FOR GEOLOGIC
EXPLORATION TECHNIQUES (TWO YEAR PROGRAM)

	Geologists	Support Personnel
1. Review of existing data	1	1.5
2. Field work and outlining of potential areas	1	1.5
3. Formulation and conduct of drilling program	1	1.5
4. Interpretation of results, recommendations, and final report writing	1	1.5
Total Man-Years	4.0	6.0

A total of about 25 exploratory holes averaging about 1,500 feet in depth is anticipated to define the potential shale deposit. An exploratory hole having a depth of 1,500 feet normally requires about a week to drill, so an exploration program involving the drilling of 25 holes requires about 6 months to complete. A drill rig capable of routinely drilling 1,500-foot exploration holes normally requires a crew of three. Total manpower requirements for 6 months of drilling thus amount to about one and one-half man-years.

4.4.2b Materials and Equipment

The materials and equipment required for geologic techniques are standard for geologic exploration, and include office space and supplies, appropriate maps, access to a properly stocked library and well log file, drafting and map-making facilities, and materials for report writing. For the field work and drilling parts of the exploration program, field vehicles and equipment are also required.

Most of the materials and equipment for drilling methods will not generally be provided by those conducting the exploration, but will be provided by a contractor who is commissioned for the drilling. This equipment includes such items as a drill rig, water truck and/or air compressor, drill pipe and bits, and core barrel (if applicable). Facilities and equipment must also be provided for the well-site geologist, including a logging trailer, and samples description and collection material. Borehole geophysical equipment, including a logging truck and appropriate sondes (probes) are usually provided by a contractor specializing in well logging.

4.4.2c Economics

The costs of exploration can be derived from the manpower, materials, and equipment requirements. Order-of-magnitude costs for geologic exploration personnel are shown in Table 4-15. These costs assume unit costs of \$60,000 per man-year for professionals (geologists) and \$40,000 per man-year for non-professionals (support personnel). Materials and equipment for geologic exploration are assumed to be available from existing facilities. In any case, materials and equipment costs for geologic exploration are negligible compared to the personnel costs.

TABLE 4-15. ESTIMATED MANPOWER COSTS FOR
GEOLOGIC EXPLORATION TECHNIQUES

Personnel	Man-years	Manpower Costs
Geologists	4.0	\$ 240,000 ^a
Support	6.0	\$ 240,000 ^b
Total		\$ 480,000

^aAssumes cost for professionals of \$60,000 per man-year; cost includes overhead.

^bAssumes cost for non-professionals of \$40,000 per man-year.

Assuming a man-year cost of \$40,000, the manpower costs for the drilling program total \$60,000. Equipment rental and operating costs amount to about \$6,000 per week for 25 weeks, totaling \$150,000. Total cost for the drilling program thus amounts to approximately \$200,000. An unknown and probably negligible cost is associated with bore hole geophysical logs.

4.4.2d Water Requirements

The water requirements for the application of geologic techniques are insignificant. A small quantity of water may be needed for the drilling program, but this amount is insignificant in the total water requirements of an oil shale mining and processing operation.

4.4.2e Land Requirements

No permanent commitments of land are required for either geologic techniques or the drilling program. Small amounts of land are temporarily devoted to drill sites during drilling operations. Areas serving as drill pads must subsequently be revegetated.

4.4.2f Ancillary Energy

Small quantities of fuel for field vehicles are required during geologic field work. Larger but still relatively minor amounts of fuel are used for operating drill rigs during the drilling program.

4.4.3 Outputs

Only a few minor residuals are associated with exploration activities for oil shale.

4.4.3a Air Emissions

Some air pollutants are generated by field vehicles and drilling equipment during exploration, but the quantities are small. The major pollutant is dust generated during drilling and from other land disturbances.

4.4.3b Water Effluents

No significant quantities of water effluents are produced by geologic techniques. A small quantity of drilling fluid may be generated during rotary drilling operations. This effluent is disposed in a small pond. The potential for surface and subsurface pollution is minimal and highly localized. However, the site of the exploration activities will suffer increased sediment runoff from the various land disturbances.

Small quantities of ground water may be intercepted during drilling. The environmental hazard associated with discharging these small quantities is likely to be minor. Alternately, the intercepted ground water may be ponded and subsequently evaporated.

4.4.3c Solid Wastes

Little solid waste is produced during either the geologic investigation or drilling phases of exploration. Small quantities of drill cuttings are generated, and disposed in a pond with drilling fluid.

4.4.3d Noise Pollution

No significant noise is generated by activities associated with geologic investigations. Only local and temporary noise is produced by rig operations during the exploratory drilling.

4.4.3e Occupational Health and Safety

During geologic field work, personnel are exposed to some very minor hazards such as falls and heat prostration. Drilling operations pose greater but nevertheless minor hazards to crew personnel. Injuries associated with equipment operation occur frequently on drill rigs.

4.4.3f Odors

Odors generated during exploration are associated with the operation of diesel equipment and field vehicles. These odors are chiefly associated with the production of sulfur dioxide and nitrogen oxides. The odors are local and temporary and are thus not likely to be a nuisance.

The inputs and outputs of oil shale exploration are summarized in Table 4-16.

4.4.4 Social Controls

As noted in Section 4.3, most oil shale lands (approximately 85%) are under federal title; therefore, the discussions that follow will primarily be devoted to controls over activities related to exploration on federal lands. Further, since most oil shale lands have been identified for many years, the following discussion will not include laws or regulations for jurisdictions that have no oil shale to regulate. Regulations for states with jurisdiction over oil shale (Wyoming, Colorado, and Utah) are discussed below.

TABLE 4-16. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED
WITH THE EXPLORATION OF OIL SHALE
IN THE WESTERN U.S.

Inputs

Manpower	
• geological activities	10 man-years
• drilling activities	1.5 man-years
Materials and Equipment	
• vehicles	Supplied by contractor
• drilling rigs	
• well logging	
Economics ^a	
• geological activities	\$400,000
• drilling activities	\$200,000
Water	Negligible
Land	Temporary and negligible
Ancillary Energy	Minor

Outputs

Air Emissions	Minor
Water Effluents	Minor
Solid Wastes	Minor
Noise	Temporary
Occupational Health and Safety	Negligible
Odors	Temporary and negligible

^a1977 dollars

4.4.4a Exploration on Federal Lands

Because most oil shale resource locations are known, there are no regulations in effect now which control oil shale exploration. Section 4.5.4.1 will discuss the prototype lease used in 1973, although there are no guarantees that a similar procedure will be used for future leases.

4.4.4b Exploration on Indian Land

No Indian lands are covered by the six prototype leases. An Indian Reservation in Utah, the Uintah and Ouray Reservation, is near the oil shale lease land. The leasing procedure for Indian oil shale land will probably be the same as for other energy resources on Indian land described in Chapter 2.

4.4.4c Exploration on State Land

Because the rich oil shale resources are located primarily in Colorado, Utah and Wyoming, only social controls related to oil shale development in those states will be discussed. Each state's oil shale development program is described below.

The state of Colorado has no oil shale exploration or leasing program for its state lands because the State owns very little if any oil shale.¹ Therefore, no statutes or regulations specifically apply to oil shale exploration.

¹Phillips, David F. "Legal Mechanisms for Access to Coal and Oil Shale", Stanford Research Institute, p. 7-47 (1975).

Statutes in Wyoming allow the State Board of Land Commissioners of Wyoming to lease the state lands for mining purposes.¹ Also under state law, when patents of state lands are issued to individuals, the minerals are reserved by the state. Therefore, leasing is the only method available for acquiring minerals, including oil shale, on state lands.

The Board of Land Commissioners is given wide discretion in its regulation of leasing. The only available method of acquiring land for exploration is to file a lease application on vacant land. The applicant then has priority on that land until the Board decides whether to lease or not. New regulations for oil shale leasing are being written and it is not known whether there will be new exploration provisions.

Utah appears to allow oil shale exploration under two separate systems. The exploration permit generally available for minerals on state lands in Utah is described below; the method of exploration under the oil shale lease will be described in section 4.5.4.1. The feasibility of the general permit is questionable for oil shale because of its limitation to a maximum of 160 acres per township per person. Table 4-17 summarizes the permit in Utah.

¹During the Depression the Wyoming Farm Board acquired ownership of some farm land through foreclosures. State regulations allow both Boards to administer the leasing provisions, but in practice, the Board of Land Commissioners handles all of it. See reference on previous page.

TABLE 4-17. OIL SHALE EXPLORATION PERMIT FOR UTAH

Item	Statutes	Summary
Agency	§65-1-18	State Land Board
Rental	§40-1-13	160 acres maximum per township per person, with \$250 worth of work completed every six months per township. No ore to be removed.
Duration	§40-1-13	One year maximum, with yearly renewals available
Other Information	§40-6-5	If developer plans to drill (either exploratory or production) the Board of Oil, Gas, and Mining has the authority to require: a) security (for plugging) b) notice of intent to drill c) filing of well log
	§65-1-18	Note: This section also allows for prospecting under the lease itself--see Utah Oil Shale leasing for terms of section.

4.5 MINING AND PREPARATION

Two major options are available for oil shale development. These are:

- 1) mining of the shale deposit, followed by surface processing of the mined-out shale, and
- 2) underground or in-situ processing.

These development options are illustrated in Figure 4-4. This section describes those mining operations required for each processing scheme. Processing technologies are discussed in Section 4.6. Reclamation activities associated with mining and processing operations are discussed in Section 4.7.

Mining operations are required for both surface and (some) underground processing schemes. As illustrated in Figure 4-4, surface or underground mines can supply shale for surface shale processing. Shale excavated during modified in-situ development mining can also be processed on the surface. Underground and surface mining are discussed in Sections 4.5.1 and 4.5.2, respectively. In-situ development mining is discussed in Section 4.5.3. Social controls for mining are discussed in Section 4.5.4.

Associated with the mining of oil shale are crushing and screening operations required to prepare shale for surface processing. These operations are described in Section 4.5.1, Underground Mining. The same crushing and screening operations are required to prepare shale supplied from surface mines.

The following three sub-sections contain descriptions of the various mining technologies, and report the input requirements and outputs associated with each technology. Input

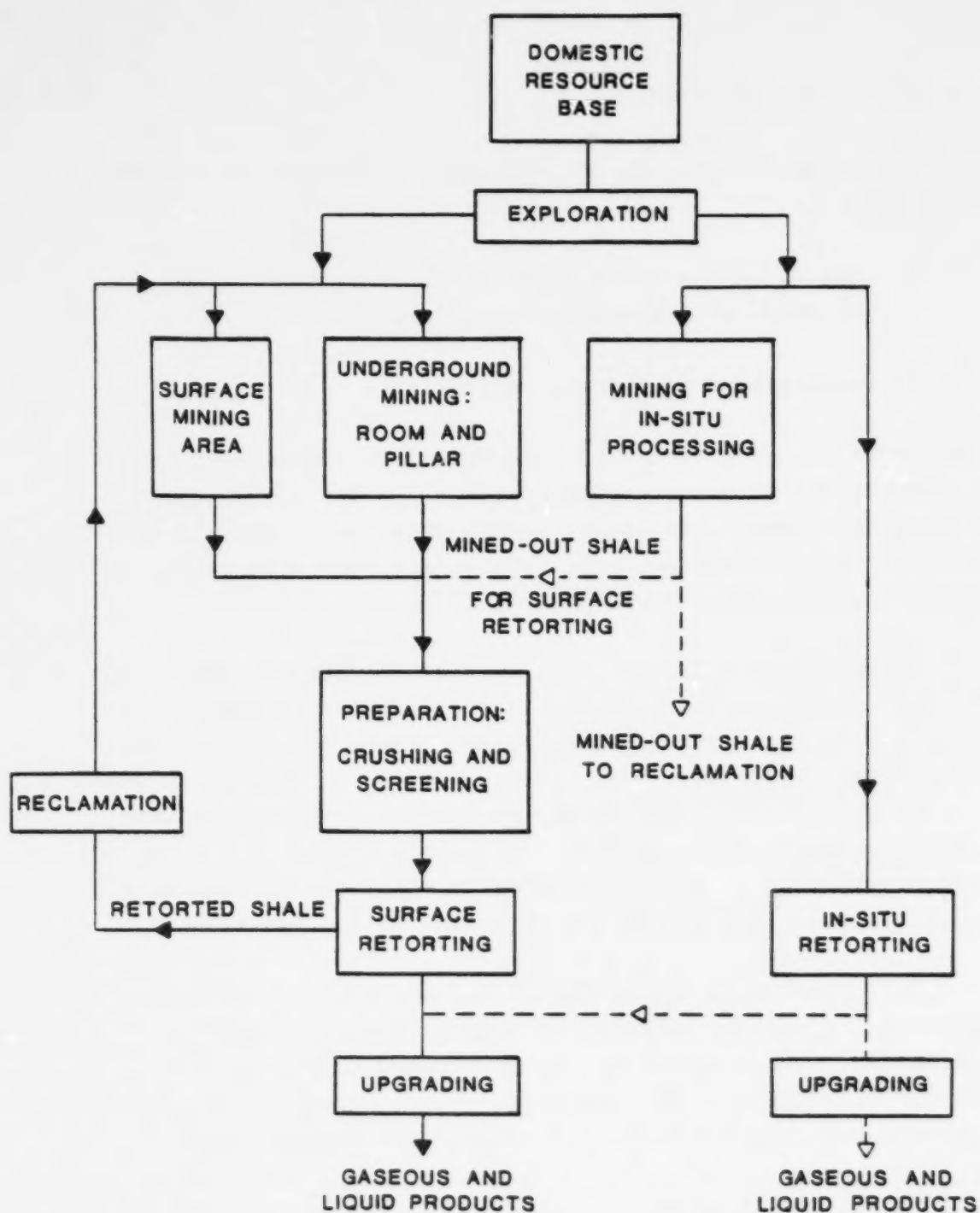


Figure 4-4. Oil Shale Development Schemes.^a

^aDashed lines show process options, e.g., shale mined during modified in-situ developments can be processed on the surface or disposed.

requirements discussed in this report include: manpower requirements, materials and equipment requirements, economics, water requirements, land requirements, and ancillary energy requirements. The outputs described in this report are air emissions, water effluents, solid wastes, noise pollution, odors, and occupational health and safety hazards.

4.5.1 Underground Mining

4.5.1.1 Technologies

Most actual experience in oil shale mining has involved underground mining techniques. Early development of underground mining was undertaken by the Bureau of Mines in its oil shale program during 1944-1956. A demonstration mine was opened at Anvil Points, Colorado, in a 73-foot section of the Mahogany zone to demonstrate the feasibility of room-and-pillar mining methods, to develop and test equipments, and to determine mining costs and resource recovery. Subsequent work by industry has utilized the mining method demonstrated by the Bureau, but has incorporated equipment modernization and improvements in techniques.¹

Union Oil operated a mine from 1955 through 1958 on a property located on the east fork of Parachute Creek in Colorado. Their efforts produced over 70,000 tons of shale for Union's retort development programs.²

¹Schramm, L. W. "Shale Oil", Section from Bureau of Mines Bulletin No. 650, U.S. Department of the Interior. Mineral Facts and Problems. 1970. pp. 185-202.

²Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 10.

The Colony Development Operation initiated a prototype mining development in 1964. Colony had successfully mined shale at rates of 1200 tons/day (and higher) before suspending operations in 1973.^{1,2} Colony later proposed construction of a commercial shale oil mine and plant near Parachute Creek, Colorado. Underground mining was to remove 61,000 tons of shale daily via conventional room-and-pillar mining.³ A draft environment impact statement (EIS) on the proposed development was made available to the public on December 12, 1975.⁴ The final EIS was completed in 1977.

The early development plans for oil shale development on federal oil shale lease tract C-b in Colorado anticipated the room-and-pillar mining of 66,000 tons per day (TPD). The excavated shale would have supported the production of 50,000 barrels of oil per day (BPD).⁵

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 10.

²Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. 260.

³Colony Development Operation. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado, Vol. 1. Atlantic Richfield Company (Operator), Denver, Colorado. 1974.

⁴U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975.

⁵Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Prepared for Area Oil Shale Supervisor. February 1976.

The White River Shale Project earlier anticipated the room-and-pillar mining of 80,000 TPD on tracts U-a and U-b,¹ with the eventual mining of 160,000 TPD. These shale excavation rates would have supported the production of 50,000 and 100,000 BPD.^{2,3}

In 1976, developers of both tracts C-b and U-a/U-b requested suspension of their oil shale leases. Developers of tract C-b later rejected their earlier plan for underground mining of oil shale. Instead, the C-b developers planned for the in-situ processing of the shale resource. That in-situ development is discussed in Sections 4.5.3 and 4.6.2.1.⁴

The status of the White River Shale Project is uncertain due to the continuing litigation involving unpatented mining claims on tracts U-a and U-b.

To date, underground mine developments have emphasized the use of room-and-pillar mining techniques. A description of room-and-pillar mining is found below. This description conforms to those plans originally proposed for the development of oil shale tract C-b.

¹The leasees of tracts U-a (Phillips Petroleum, Sun Oil) and U-b (Phillips, Sun, Sohio) proposed joint development of the two adjoining tracts.

²White River Shale Project. Detailed Development Plan for Oil Shale Tracts U-a and U-b, as cited in: Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 54.

³Differences in shale excavation requirements for developments producing the same quantities of shale oil are attributable to differences in oil contents of the shale resources.

⁴Novak, Alys. "Oil Shale - 1976/1977," Shale Country 2 (12): 2-6, December 1976.

Various mining systems have been suggested as alternates to room-and-pillar mining. An abbreviated discussion of several of these techniques follows the room-and-pillar mining description.

In room-and-pillar mining, pillars of shale are left in place at appropriate intervals within the mine to provide roof support. The room-and-pillar mining technique is illustrated in Figure 4-5.

If the height of the mining zone is 60 or 75 feet, at least two passes are required to mine the oil shale. In that case, the mining cycle involves one pass using upper-level or face-mining equipment, followed by one or more passes with lower-level or bench-mining equipment. If the mining zone is 35 feet high, only one pass is required using upper-level equipment. If the height of the mining zone is 45 feet, either a single or multiple-pass may be used.¹

The optimum mining zone thickness depends upon the geotechnical properties of the rock mass and upon mining and retorting costs. For example, the maximum extraction ratio for a 75-foot mining zone using room-and-pillar techniques has been estimated to be from 30 to 50%. For a 35-foot mining zone, this ratio may be 40 to 60% or higher. Cameron Engineers has estimated overall resource recovery for a 40-foot mining zone to be 65%.² This difference in extraction efficiency is largely attributable to the difference in rock properties of each interval. In

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. II-22.

²Hoskins, W. N., et al. "A Technical and Economic Study of Candidate Underground Mining Systems for Deep, Thick Oil Shale Deposits", Quarterly of the Colorado School of Mines 71 (4): 199-234. 1976.

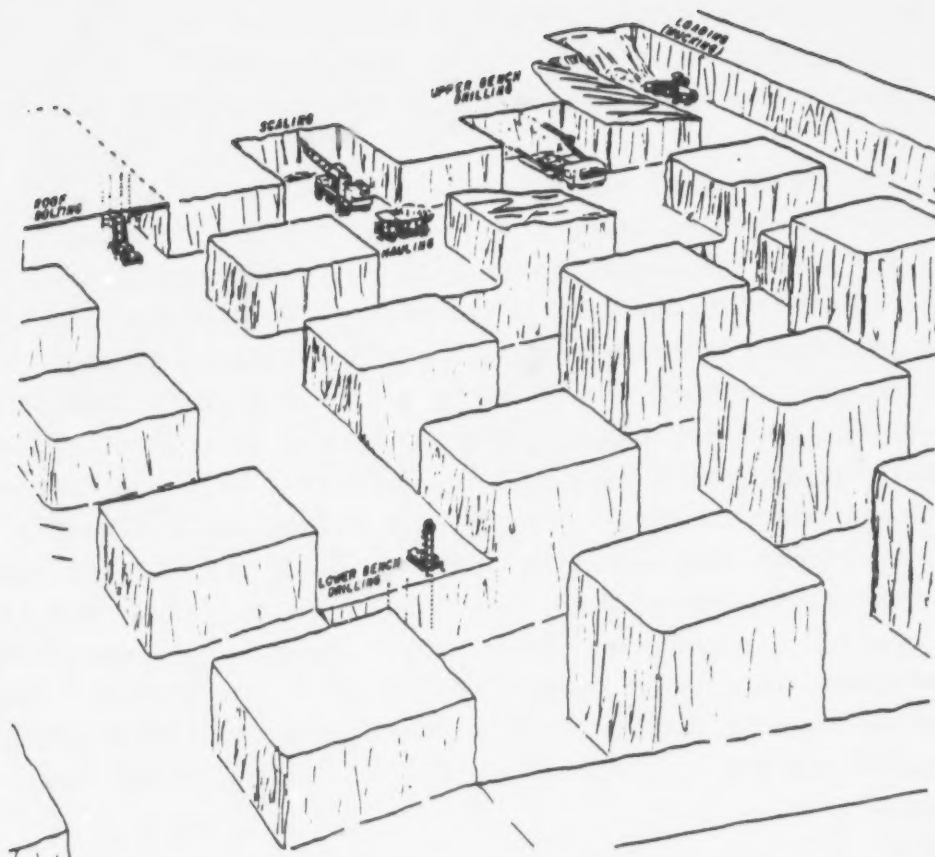


Figure 4-5. Room-And-Pillar Mining.

Reference: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b. Volume I, Prepared for Area Oil Shale Supervisor, February 1976. P. II-23.

(Originally reported in: Colony Development Operation. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado. Volume I, 1974. P. 11)

going from a thinner to thicker mining zone, some zones of weaker rock must be included and support pillars must be larger. It is possible that more oil shale could be recovered from the target shale resource by mining a thinner and richer zone than could be obtained by mining a thicker and leaner zone.¹

The upper-level mining cycle proceeds as follows. First, the face is drilled using a face-drill jumbo. An upper-level charging rig then loads the drilled round with explosives. The round is then blasted during the next shift change. Fly rock from the blast is removed by a front-end loader and the blasted rock or muck is wetted by a water truck to control dust. The rock is then loaded into trucks by a front-end loader for haulage to the primary crusher. When the distance to the crusher is small, a front-end loader hauls directly to the crusher without using trucks. After the blasted rock is completely removed, the ribs (sides), back (roof) and face are scaled to remove any loose rock. The mining zones being considered are bounded at the top by distinct parting planes. As these parting planes normally pull well, minimal scaling is required and scaling can safely follow loading in the work cycle.²

Following the scaling operation, a front-end loader removes the scaled material. The back exposed by the blast is then roof-bolted in accordance with accepted safety standards. If needed, drain holes to relieve hydrostatic pressures above the roof and below the floor are drilled. Instruments to monitor

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-2.

²*Ibid.*

rock behavior are installed as required. When this is done, the cycle is completed and the face is readied for drilling of the next round.¹

The lower-level cycle, if used, begins when sufficient upper-level mining is completed to allow both cycles to proceed without interference. The lower-level cycle starts with the drilling of multiple vertical holes from the top of the mine bench. These holes are then loaded with explosives and blasted during a shift change. This is followed by fly rock clean up and muck pile wetting. The muck is loaded using the same method as in upper-level loading. The area is then scaled and the scaled rock removed. After installation of any rock mechanics instrumentation, the bench is ready for the cycle to begin again.²

Future underground mining may utilize continuous mining machines. The machines have not yet been developed but are potentially desirable for oil shale excavation. The continuous miners allow mining to proceed more rapidly, are less labor-intensive, and produce more stable mine tunnels than conventional equipment. However, continuous mining machines are more capital-intensive and less versatile than conventional

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan for Oil Shale Tract C-b, Prepared for Area Oil Shale Supervisor. February 1977. p. II-22.

²*Ibid.*

mining equipment. The first application of continuous miners will probably be a modification of room-and-pillar mining.^{1,2,3,4}

Generally, most ore bodies that can be mined with the room-and-pillar mining method can be extracted by the longwall method. This method consists of mining a straight face for 80 yards or more, allowing controlled subsidence into the mined-out space. Nearly 100 percent resource recovery is possible. Surface subsidence and consequent disruption of aquifers and surface streams are likely.⁵ Longwall mining has been demonstrated only on thin seams.

Other alternate mining systems have been studied by Cameron Engineers. Mining methods evaluated for the Bureau of Mines included: square-set stoping, shrinkage stoping, cut-and-fill stoping, sublevel caving, sublevel stoping, room-and-pillar, longwall, and block caving.⁶ Of those systems selected for cost evaluation, room-and-pillar mining was shown to have the lowest

¹U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975, pp. IX-6,7.

²U.S. Congress, Senate Committee on Interior and Insular Affairs. Legislative Authority on Federal Agencies with Respect to Fuels and Energy. Washington, D.C.: Government Printing Office, 1973.

³University of Oklahoma, Science and Public Policy Program. Energy Alternatives: A Comparative Analysis. Council on Environmental Quality. University of Oklahoma. May 1975.

⁴East, J. H., Jr., and E. D. Gardner. Oil Shale Mining, Rifle, Colorado, 1944-56. Bureau of Mines Bulletin 611. Washington, D.C.: Government Printing Office, 1964, p. 127.

⁵U.S. Bureau of Land Management, *op.cit.*, pp. IX-4,5.

⁶Stoping is a mining method removing rock via a series of steps either at or below the mining level.

annualized production cost. Cameron reports contain more detailed descriptions of the various mining techniques.^{1,2}

The oil content within the extracted shale may vary widely because shale zones contain layers of varying quality. Generally, the target zone for mining consists of 30 gallons oil per ton or higher. Lower yield layers of oil shale above the mineral zone are treated as overburden. However, there is no separation of shale within the zone into high- and low-quality seams.

Much of the mined oil shale will require crushing and sizing prior to processing. Sizing operations performed on oil shale may include primary, secondary, and tertiary crushing; screening; and briquetting. The required size of the crushed oil shale depends on the specific processing technology being applied. TOSCO processing requires that the shale be ground to less than 1.2 cm while the Union and Paraho processes can accomodate shale up to 8.5 cm. Typical operations in a shale sizing facility are shown in Figure 4-6. The throughputs shown in Figure 4-6 correspond to the excavation of 66,000 TPD. That level of excavation can supply a surface processing facility producing 50,000 BPD assuming an average grade shale containing 35 gallons of oil per ton.³

¹Hoskins, W. N., et al. "A Technical and Economic Study of Candidate Underground Mining Systems for Deep, Thick Oil Shale Deposits", Quarterly of the Colorado School of Mines 71 (4): 199-234. 1976.

²Cameron Engineers. A Technical and Economic Study of Candidate Underground Mining Systems for Deep, Thick Oil Shale Deposits. NTIS, PB 249-884/AS. July 1975.

³Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, TX: Radian Corporation, September 1977, p. 22.

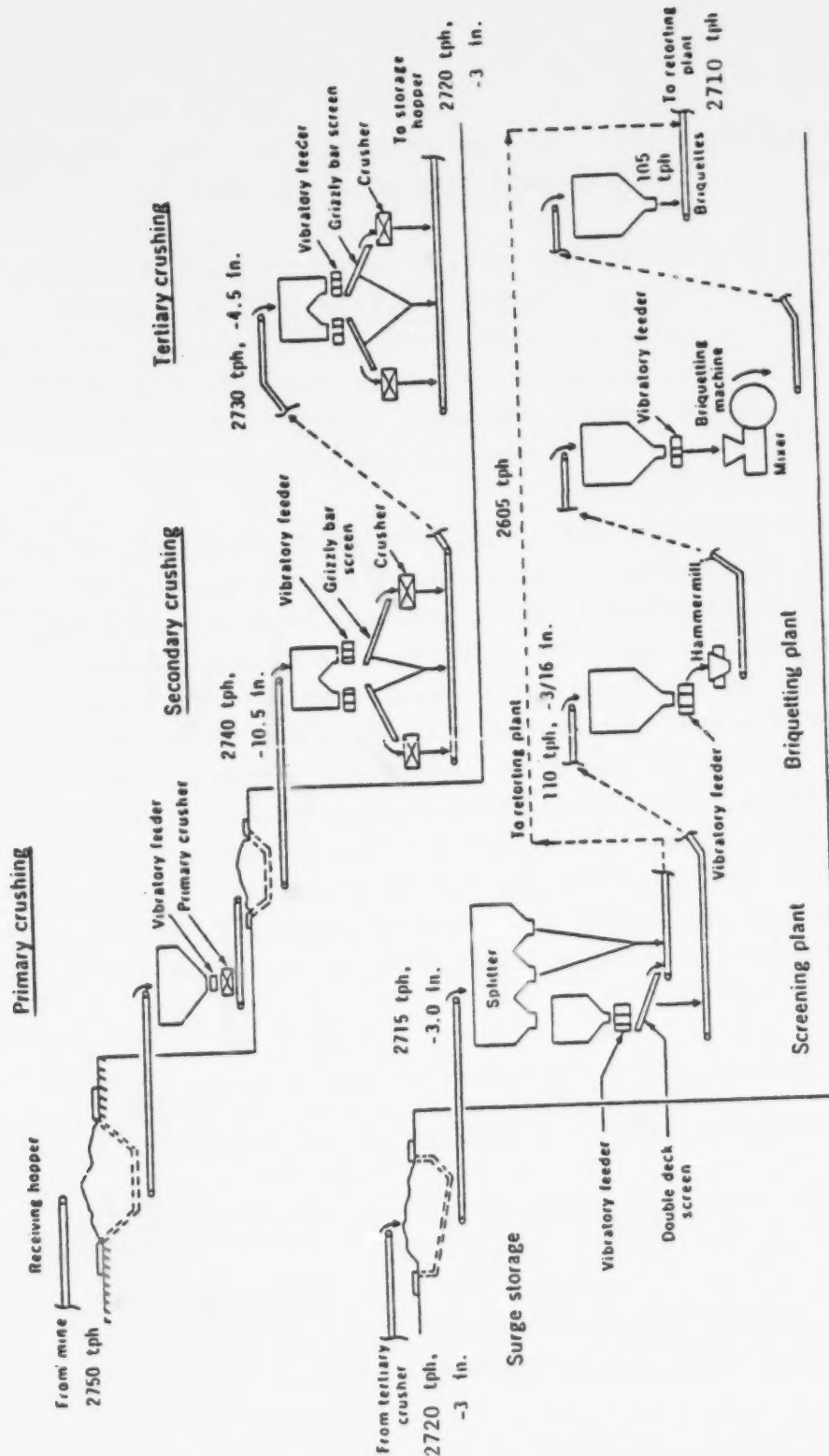


Figure 4-6. Shale Sizing Operations.

Reference: U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program. 6 Vols. Washington, D.C. Government Printing Office, 1973.

To minimize the costs of transporting raw shale, the crushers are located close to the blasting operation, usually within the room-and-pillar mine or in the surface mining pit. From the primary crushers the shale is conveyed to secondary and tertiary crushers outside the mine or pit. The remaining sizing operations may be performed at the mine site or at the processing site.¹

After secondary and tertiary crushing, the shale is conveyed to shale storage hoppers. From the storage hoppers, the shale may be fed directly to the processing facility. If the processor cannot accept fine particles, the fines are separated from the shale by a screening process and compacted and formed into briquettes. These briquettes are suitable for routing to the processor along with other shale feedstock or are discarded.²

The crushing operation is designed to maintain a continuous feed to the retort. This objective will be accomplished in part by maintaining a storage pile of coarse ore and a storage bin of fine ore. No storage facility for run-of-mine ore will be needed. The mine haulage operation is entirely dependent on the operation of the primary crusher. Should a breakdown occur in the primary crusher or the conveyor to the coarse ore storage, haulage from the mine will be interrupted. To avoid shutdown of the retorting and upgrading facilities, sufficient storage of coarse ore will be maintained to allow uninterrupted operation of the downstream processing facilities for about one month. If the final crusher breaks down, the

¹Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977, p. 24.

²*Ibid.*, pp. 24-26.

amount of stored fine ore will be enough to operate the retort for approximately 5 hours.¹

4.5.1.2 Input Requirements

This section reports inputs required for the operation and maintenance of a room-and-pillar underground mine. The various manpower, equipment, water, land, and energy requirements are largely based on data reported by Ashland Oil, Inc. and Shell Oil Company in the 1976 Detailed Development Plan (DDP) for Oil Shale Tract C-b.² Generally similar data were reported by the U.S. Department of the Interior in the EIS for the Colony Development Operation (December, 1975).³ Estimates of capital requirements and annualized operating costs are likewise based on data reported in the DDP and in the EIS.

The inputs described in this section are representative of a room-and-pillar underground mine supplying shale to surface facilities producing 50,000 barrels of shale oil per day. The mine extracts approximately 66,000 TPD. This production equals the demand of the processing plant, assuming that the plant operates at approximately 90 percent capacity on a yearly basis. The average oil content of the extracted shale is 35 gal/ton.

Inputs for alternate underground mining techniques will differ from those reported below.

¹Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977, p. 26.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. p. IV-10.

³U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. p. II-97.

4.5.1.2a Manpower

Manpower requirements for mining operations supplying 66,000 TPD to a surface processing plant have been reported by Ashland and Shell in the DDP for oil shale tract C-b. These requirements are tabulated in Table 4-18 and reflect the most recent data available from documents available to the public.¹ Earlier estimates from the Colony EIA and EIS were lower than those reported in the DDP.^{2,3}

TABLE 4-18. MANPOWER REQUIREMENTS FOR ROOM-AND-PILLAR UNDERGROUND MINING ^{a,b}

Personnel	Number Required
Mine Operators	346
Mine Maintenance	179
Mine Salary Management	53
Mine Supervisors and Clerical	22
Crushing/Disposal Support	143
Total	743

^aProduction Capacity of Surface Complex: 50,000 BPD

^bExcavation Requirements: 66,000 TPD

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-10.

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-10.

²Colony Development Operation. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado, Volume I. Atlantic Richfield Company (Operator), Denver, Colorado. 1974

³U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. p. II-97.

The manpower requirements in Table 4-18 relate only the personnel required for full-scale commercial operations. Accurate estimates of the skill breakdowns for the construction personnel required to establish the site are unavailable. However, total manpower requirements to develop the entire oil shale complex have been reported by Ashland and Shell and are shown in Figure 4-7. Peak construction employment is approximately 3300.¹

4.5.1.2b Materials and Equipment

Detailed materials and equipment requirements have not been prepared by potential underground mine developers. However, Ashland and Shell have described the mining equipment likely to be used in a commercial development. Their description is reproduced in Table 4-19.²

The Federal Energy Administration has estimated equipment requirements for an underground mine excavating 140,000 TPD oil shale. While the data in the FEA report are now somewhat outdated, a 66,000 TPD mine may be assumed to require about half of the equipment required for the 140,000 TPD mine. The equipment required for the 66,000 TPD mine are scaled from the data in the FEA report and are presented in Table 4-20. The equipment list is not complete and may be based on outdated information. Crushing and screening apparatus are omitted from the equipment list.³

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. Figure IV-3.

²*Ibid.*, p. IV-21.

³Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. H-168.

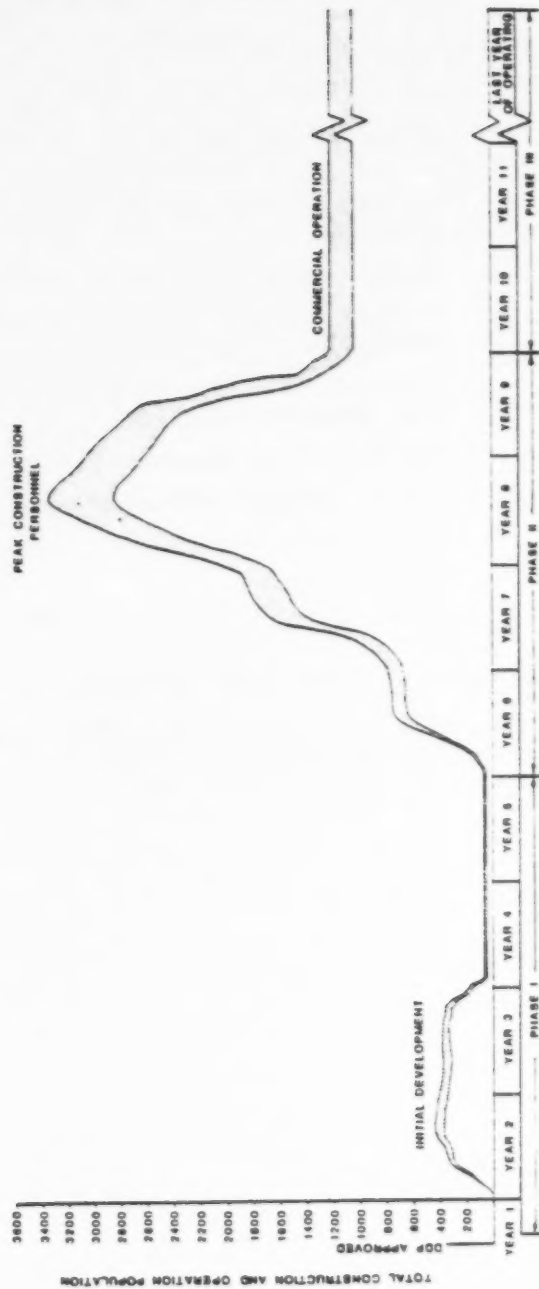


Figure 4-7. Project Manpower Estimate.

Reference: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b. Volume I. Prepared for Area Oil Shale Supervisor. February 1976. Figure IV-3.

TABLE 4-19. DESCRIPTION OF COMMERCIAL MINING EQUIPMENT

Item	Description
1) Haulage Trucks	End dump rock trucks, 30 to 100 ton.
2) Face Drills	Large, self-propelled 2 to 4 boom jumbo with 15 to 30 foot booms.
3) Down Hole Bench Drills	Standard self-propelled, open-pit down hold drill.
4) Front End Loader	Bucket capacity of 5 to 15 cubic yards.
5) Scaler	Standard backhoe with scaling pick mounted on end of boom arm.
6) Roof Bolter	Self-propelled, two-boom roof bolt drill with personnel platform.
7) Explosive Loader	Self-propelled explosive-charging machine.
8) Explosive Trucks	Trailer mounted explosive magazines.
9) Haul Road Maintenance Equipment	Grader and water trucks.
10) Field Mechanics and Supervisory Vehicles	Diesel powered pickups, 3/4 ton.

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV 21.

TABLE 4-20. ESTIMATED EQUIPMENT LIST FOR UNDERGROUND MINING OF 66,000 TPD

Equipment	Description	Number Required	Capacity	HP
Heading jumbo drills	Hydraulic electric with two drills	6	--	150
Bench jumbo drills	Hydraulic electric with two drills	3	--	150
Powder trucks	Diesel drive with pneumatic delivery system	5	3 tons	100
Scaling and roof bolting rigs	Diesel drive with aerial lift	5	--	500
Front end loaders	Diesel drive	7	20	700
Haulage trucks	Diesel drive	20	75	700
Motor Patrols	Diesel drive	4	--	150
Bulldozers	Diesel drive	10	--	700
Road graders	Diesel drive	2	--	225
Water trucks	Diesel drive	5	--	--

Note: Actual equipment list for underground mining may differ substantially from the above list.

Source: Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. H-168.

As estimated for use in a Battelle computer model, steel requirements during plant construction amount to:

Crushing and Screening	3700 tons
Mining	3300 tons
Briquetting	300 tons

These values were extrapolated from data in the FEA report and may not be accurate.¹

4.5.1.2c Economics

Preliminary capital cost estimates for a mine associated with a 50,000 BPD shale oil complex are shown in Table 4-21. The costs are those reported by Ashland and Shell in the DDP for oil shale tract C-b. The estimates are based only on preliminary engineering design and project scheduling, and do not include interest during construction and deferred capital expenditures. The capital cost estimates reported in Table 4-21 include only those costs directly related to the mine, and exclude costs for general facilities, indirect costs, and working capital. Miscellaneous capital requirements (i.e., costs for general facilities, indirects, and working capital) for the entire oil shale complex are reported in Section 4.6.1.2, Surface Retorting Technologies. The costs in Table 4-21 are indexed to 1977 from the October 1975 costs reported in the DDP. Costs for the processed shale disposal are included in

¹Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. F-109.

TABLE 4-21. CAPITAL COST ESTIMATES FOR AN
UNDERGROUND SHALE MINE^{a, b}

Plant Design and Construction	
Mining, Crushing, and Processed	\$110,000,000
Shale Disposal	
Site Development, Roads and Dams	31,000,000
Commercial Mine Pre-Development	10,000,000
Mining and Disposal Mobile Equipment	21,000,000
Development Mining	17,000,000
TOTAL	\$190,000,000

^aShale oil production capacity of 50,000 BPD; shale excavation of 66,000 TPD.

^bCosts are in 1977 dollars, and are indexed from those reported by Ashland and Shell by 1.10. General facilities costs, indirect costs, and working capital are reported for the entire facility in Section 4.6.1.2.

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. I-22.

Table 4-21 but are more closely associated with processing activities.¹

Operating cost estimates have not been prepared by potential underground mine developers. However, data reported in the DDP and EIS are sufficient to construct preliminary cost estimates. The labor costs are estimated from the labor requirements reported by Ashland and Shell in the DDP. Utilities' costs are estimated from the power and fuel requirements reported in the DDP and in the EIS. All other costs are estimated as percentages of the capital or labor costs. These estimates are shown in Table 4-22, and are based on preliminary, incomplete data.^{2,3,4}

4.5.1.2d Water Requirements

Most of the water required for an underground mining operation is needed for dust control. Ashland and Shell have estimated mining water requirements as 450 gpm (730 acre-ft/year) for a 66,000 TPD mine. About 350 gpm of untreated mine-water can be used for road wetting and muck pile dust control. About 100 gpm of treated minewater are required for dust control spray systems.⁵ An additional 150 gpm (240 acre-ft/year) are required for dust control for primary crushing and

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. I-22.

²*Ibid.*

³U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975.

⁴Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b, Prepared for Area Oil Shale Supervisor. February 1977.

⁵Ashland Oil, Inc. and Shell Oil Co., *op.cit.*, p. IV-22.

TABLE 4-22. ANNUALIZED OPERATING COSTS FOR AN UNDERGROUND SHALE MINE^{a, b}

Component	Cost
Direct Costs	
Mine Operators ^c	\$ 5,200,000
Mine Maintenance ^c	2,700,000
Crushing/Disposal Support ^c	2,200,000
Miners Salary Management ^d	1,100,000
Mine Supervisors and Clerical ^d	440,000
Total Personnel Costs	12,000,000
Operating Supplies ^e	1,900,000
Maintenance Materials ^f	2,700,000
Utilities	
Electricity ^g	25,000,000
Water ^h	—
Diesel Fuel ⁱ	1,800,000
Fixed Costs	
Depreciation ^j	19,000,000
Taxes and Insurance ^k	5,700,000
Plant Overhead ^l	6,000,000
Total	\$74,000,000 \$4.05/bbl

^aShale oil production capacity of 50,000 BPD; shale excavation of 66,000 TPD.

^bCosts are in 1977 dollars and include only those costs directly attributed to the mining operation.

^cCalculated @ \$15,000/man/year.

^dCalculated @ \$20,000/man/year.

^eCalculated @ 1% of the fixed capital costs.

^fCalculated @ 100% of maintenance labor.

^gCalculated @ \$0.04/kwh.

^hEssentially all water requirements are met by use of minewater.

ⁱCalculated @ \$0.50/gal.

^jCalculated @ 10% of fixed capital.

^kCalculated @ 3% of fixed capital.

^lCalculated @ 50% of total labor costs.

Note: Rates for calculating fixed costs, plant overhead, and costs for operating supplies and maintenance materials are largely based on Peters, M. S. and K. D. Timmerhaus. Plant Design and Economics for Chemical Engineers, 2nd. Ed. (New York: McGraw-Hill Book Co., 1968), pp. 132-141.

Source: U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975.

Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume 1, Prepared for Area Oil Shale Supervisor. February 1976.

Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b, Prepared for Area Oil Shale Supervisor. February 1977.

coarse ore storage.¹ Personnel requirements are not significant. Total water usage for mining and crushing amounts to 600 gpm. (970 acre-ft/year).

Consumptive uses during construction include concrete manufacture, dust control, fill compaction, and personnel uses. Quantities for these uses amount to 500-700 gpm (800-1100 acre-ft/year). The entire requirement can probably be met by water from dewatering operations but water treatment may be required.²

4.5.1.2e Land Requirements

Ashland and Shell have projected surface disturbances associated with an underground shale mining development. Estimates of the acreage disturbed by underground mining are reported in Table 4-21. Areas required for the disposal of processed shale are associated with shale processing and are discussed in Section 4.6.1.2.

4.5.1.2f Ancillary Energy Requirements

Ancillary energy requirements for an underground mine have been reported by developers in the DDP and EIS, and are tabulated in Table 4-24. The energy recovery ratio for underground mining can be determined by dividing the total heating value of the oil shale by the sum of this number and the above ancillary energy requirements. The energy recovery ratio is determined to be 0.99.

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-63.

²*Ibid.*, p. IV-62.

TABLE 4-23. SURFACE AREAS DISTURBED BY AN UNDERGROUND
MINING DEVELOPMENT EXTRACTING 66,000 TPD^a

Disturbance	Area Disturbed (Acres)
Mine Surface Facilities	25-35
Coarse Ore Conveyor	5-10
Coarse Ore Stockpile	40-55 (temporary) 35-40 (initial)
Road Construction ^b	82-115
Water in Dams ^b	150-270 ^c

^aAreas required for processed-shale disposal are discussed in Section 4.6.1.2

^bAs estimated for entire oil shale complex.

^cLand areas required for water storage or ponding vary from site to site. Most developers use the natural terrain to create large reservoirs. The quantity of minewater requiring ponding also varies from site to site.

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor.
February 1976. p. IV-9.

4.5.1.3 Outputs

This section reports the various outputs associated with the operation of an underground mine excavating 66,000 TPD. Discussions of air emissions, water effluents, solid wastes, and noise pollution are largely based on information reported

TABLE 4-24. ANCILLARY ENERGY REQUIREMENTS FOR UNDERGROUND SHALE MINING^a

	Power Requirements	Energy Usage
Electricity		
Hoisting	21,500 hp	1.18×10^6 kwh/year ^b
Underground Crushing and Conveying	5,500 hp	2.9×10^7 kwh/year ^c
Ventilation	13,000 hp	8.7×10^7 kwh/year ^d
Dewatering ^e	30,000 hp	2.0×10^6 kwh/year ^e
General Services	---	4×10^7 kwh/year
Crushing and Screening	---	1.5×10^6 kwh/year ^f
TOTAL		6.2×10^6 kwh/year ^f
Diesel Fuel	10,000 gal/d	5×10^{11} Btu/year ^g

^a Shale oil production capacity of 50,000 BPD; excavation requirement of 66,000 TPD.

^b Assumes mine operates 350 days/year, 3 shifts/day, 7 hours of hoisting/shift.

^c Assumes mine operates 350 days/year, 3 shifts/day, 6.5 hours (eff.)/shift.

^d Assumes ventilation and dewatering requirements occur 365 days/year.

^e Dewatering requirements vary from site to site and are different for different mining techniques.

^f Figure represents electricity directly used in mining. Gross power plant energy requirements can be estimated by using power plant heat rate of 9750 Btu/kwh (power generation efficiency of 35%).

^g Based on fuel usage for in-situ underground development; assumes mine operates 350 days/year; heating value for diesel fuel of 140,000 Btu/gal.

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. P. IV-28.

U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975. p. 11-17.

Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b, Prepared for Area Oil Shale Supervisor, July 1977.

by Ashland and Shell in the 1976 DDP and by the U.S. Department of the Interior in the EIS (December 1975).^{1,2}

The outputs are reported for room-and-pillar underground mining. Outputs for alternate mining technologies will differ from those reported below.

4.5.1.3a Air Emissions

Air emissions from underground mining operations originate from the mine ventilation system, the shale conveyor system, and the shale crushers. Mine vent emissions are shown in Table 4-25 and discussed below. Emissions from crushing and conveying are shown in Table 4-26. Air emissions are those reported in the Draft EIS.

Emissions from underground mining operations exit the mine vent; these emissions are tabulated in Table 4-25. The mine vent emissions originate from conventional mining operations (i.e., mining, blasting and hauling) and diesel equipment operation. Catalytic scrubbers mounted on mobile mine equipment remove essentially all of the hydrocarbons, CO, and SO₂ emitted in diesel exhaust fumes. No control devices are placed on the mine vent. In-mine watering will control dust to some extent.^{3,4}

¹U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976.

³U.S. Bureau of Land Management, *op.cit.*, p. II-16.

⁴Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions From Synthetic Fuel Production Facilities, Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, TX: Radian Corporation, September 1977.

TABLE 4-25. MINE VENT EMISSIONS, LB/HR FROM UNDERGROUND
SHALE MINE EXCAVATING 66,000 TPD

Pollutant	Emission Rate
Particulates	61
Hydrocarbons	54
NO _x	270
CO	480
SO ₂	Negligible
CO ₂	9000 ^a

^aEstimated from diesel fuel requirement; assumes complete combustion of carbon compounds in fuel to CO₂.

Source: U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975, p. II-16.
Colley, J.D., W. A. Gathman, and M. L. Owen. Emissions From Synthetic Fuel Production Facilities, Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

TABLE 4-26. PARTICULATE EMISSIONS FROM CRUSHING AND CONVEYING FOR AN
UNDERGROUND SHALE MINE EXCAVATING 66,000 TPD

	Primary Crusher, Dust Collection System	Portal Transfer Point	Feed Bin Transfer Point	Reclaim Tunnel Transfer Point	Primary Crusher, Dust Collection System Stacks (4)	Fine Ore Storage Dust Collection System
Stack Exit Diameter	5 feet	1.5 feet	4 feet	4 feet	5 feet/stack	4 feet
Total Stack Gases	62,250 acf/min	35 acf/min	730 acf/min	800 acf/min	285,000 acf/min	37,000 acf/min
Molecular Weight	29	29	29	29	29	29
Exit Temperature	Ambient	Ambient	Ambient	Ambient	60°F	60°F
Moisture Content	Ambient	Ambient	Ambient	Ambient	Ambient	Ambient
Solid Particulates	8 lb/hr	1 lb/hr	6 lb/hr	6 lb/hr	37 lb/hr	5 lb/hr

Note: acf = actual cubic feet

Source: U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES -75-62. Washington, D.C.: December 1975, pp. 11-17 to 11-22.

Approximately 22-33 lb/hr of particulates enter the mine atmosphere from drilling, hauling, and loading and are drawn into the ventilation system. For three 1-hour periods each day, blasting releases an estimated 220-330 lb/hr of particulates into the mine atmosphere. The particulates emission rate shown in Table 4-25 is an average rate (61 lb/hr).^{1,2}

NO_x emissions are largely generated by mobile mine equipment. CO and hydrocarbons are produced during mining operations and during diesel equipment operation.^{3,4} CO₂ emissions mainly originate from the combustion of diesel fuel.

Air emissions from shale sizing operations originate from crushing and screening facilities, belt conveyor transfer points, and fine ore storage silos. Table 4-26 summarizes the emissions from these sources. Emissions from the primary crusher, the fine ore crusher, the belt conveyor transfer points, and the larger storage silos are controlled by fabric filters with assumed collection efficiencies of greater than 99 percent.⁵

Emissions from the raw shale stockpile have not been estimated, but are on the order of 50 lbs/hr with wet suppression dust control.⁶

¹U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975, p. II-16.

²Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions From Synthetic Fuel Production Facilities, Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

³U.S. Bureau of Land Management, *op.cit.*

⁴Colley, J. D., W. A. Gathman, and M. L. Owen, *op.cit.*

⁵U.S. Bureau of Land Management, *op.cit.*, pp. II-17 to II-22.

⁶See Section 4.5.3, Mining for In-Situ Processing.

4.5.1.3b Water Effluents

Potential water effluents from mining operations include: excess minewater, runoff from raw shale stockpiles, and sanitary wastewaters. Volumes of these potential water effluents have not been estimated. Quantities and qualities of excess mine-water and runoffs are largely dependent on the site of the mine development.

Excess minewater can be treated for use in processing operations or routed to an evaporation pond. The desirability of treating minewater for process use depends on the minewater quality and on the required quality of process water. Ground-water quality data for oil shale tracts C-a and C-b are presented in Table 4-27. These data represent a limited number of analyses for many constituents and may not be completely representative.¹ Quantities of excess minewater are dependent on the site of the mine development and may range from small amounts to several thousand gallons per minute. A certain portion of poor quality water can be used for surface requirements such as dust control and moisturizing of processed shale. These requirements can be met by untreated minewater.²

Runoffs from raw shale stockpiles can be contained in catchment ponds. These runoffs are likely to contain inorganic salts, toxic metals, and some toxic organics (including carcinogens) that have been leached from the raw shale. However, if the catchment ponds are properly designed, the runoffs are not

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development, Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-22.

TABLE 4-27. CONCENTRATIONS (MG/L) FOR DISSOLVED CONSTITUENTS IN GROUNDWATER
IN THE PICEANCE CREEK BASIN

	Mean Values from Tract C-A		Mean Values from Tract C-B		Mean Values from Piceance Basin Sites	
	Alluvial Aquifer	Oil Shale Upper	Alluvial Aquifer	Oil Shale Upper	Oil Shale Upper	Lower
Arsenic	.000	.004	.006	.014	-	-
Barium	.003	.000	.090	.100	-	-
Bicarbonate	-	-	-	-	1220.000	550.000
Boron	1.250	.692	.720	1.500	-	-
Cadmium	.028	.002	-	-	-	-
Calcium	-	-	-	-	57.000	50.000
Chloride	-	-	-	-	42.000	16.000
Chromium	.000	.005	-	-	-	-
Copper	.524	.027	-	-	-	-
Dyanide	.002	.000	-	-	-	-
Dissolved Solids	1190.000	1140.000	1000.000	560.000	1750.000	960.000
Fluoride	.367	4.090	.97	18.000	4.600	1.400
Lead	.398	.353	.026	.013	-	-
Magnesium	-	-	-	-	80.000	60.000
Mercury	.000	.000	.003	.001	-	-
Nitrate as N	6.600	.534	3.100	.470	-	-
Potassium	-	-	-	-	2.500	1.500
Selenium	.000	.000	-	-	-	-
Silver	.006	.007	-	-	-	-
Sodium	-	-	-	-	490.000	210.000
Sulfate	-	-	-	-	430.000	320.000

Data for Tracts C-a and C-b from:

Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency, Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 122-123.

Data was originally compiled by EPA Region VIII from environmental baseline data reports.

Data for Piceance Basin from:

Department of the Interior, Simulated Effects of Oil-Shale Development on the Hydrology of Piceance Basin, Colorado, Geological Survey Professional Paper 908, 1975. p. 35.

likely to enter natural water systems. Some developers anticipate using water from catchment ponds for shale dust control and compaction.¹

Sanitary wastes can be treated onsite, with recovery of the liquid effluent for re-use. Expected volumes of these sanitary wastes have not been reported but are probably insignificant.

4.5.1.3c Solid Wastes

Negligible solid wastes are created as a direct result of mine operation.² Some overburden removal is required to open the mine. According to Hittman, the overburden excavated during mine development amounts to approximately 150,000 tons for a 50,000 BPD oil shale operation.³ The wasted material resembles the natural talus material and its disposal does not have a severe impact on the visual or aesthetic quality of the site.

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b, Prepared for Area Oil Shale Supervisor. February 1977. p. III-43.

²Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities, Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

³Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supplied by Emerging Technologies. Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Prepared for Council on Environmental Quality, National Science Foundation, and Environmental Protection Agency. Contract EQC 308. Columbia, Maryland. May 1974.

Minimal solid wastes are generated from oil shale sizing operations for the TOSCO process. However, for the Union and Paraho processes, the fines must be disposed or consumed by briquetting or by using a combination of retorts that consume the fines. Approximately 3300 TPD of fines are produced from the Union and the Paraho processes.^{1,2}

Water treatment sludges result from upgrading minewater for processing, and are discussed in Section 4.6.

4.5.1.3d Noise Pollution

Noise at the underground mine originates from normal mining operations. Sound levels within the mine are similar to those encountered in underground coal mines. Typical ranges of sound levels at worker positions are shown in Table 4-28.

4.5.1.3e Occupational Health and Safety

Health and safety hazards associated with underground shale mining have not been extensively examined. Safety hazards are those hazards chiefly associated with mining accidents. Health hazards are those dangers associated with work exposure to toxic substances. Each of these hazards is discussed below.

¹Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Texas: Radian Corporation, September 1977.

²McKee, J. M. and S. K. Kunchal. "Energy and Water Requirements for an Oil Shale Plant Based on the Paraho Processes", Presented at the Ninth Oil Shale Symposium, Colorado School of Mines, Golden, Colorado. April 1976.

³U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975. p. II-48.

TABLE 4-28. NOISE LEVELS ENCOUNTERED BY MINE WORKERS^a

Noise Source	Sound Level, dbA
Roofbolter/Scaler	107 - 118 ^b 92 - 101 ^c
Drill	80 - 104
Air Pump/Fan	90 - 105
Conveyor	90 - 105 ^d 75 - 85 ^e
Crusher/Feeder	90 - 105
LHD	90 - 108
Sump	93 - 98
Hoist	85 - 95
Diesel Trucks	74 - 109
Primary Crushing	72 - 111

^aData assumes that underground shale mines and underground coal mines have similar noise sources and characteristics.

^bPneumatic roofbolter.

^cRotary roofbolter.

^dFlighted conveyor.

^eBelter conveyor.

Source: U.S. Department of the Interior. Noise Control Proceedings: Bureau of Mines Technology Transfer Seminar, Pittsburgh, PA. January 22, 1975, pp. 6, 95.

Down, C. G. and J. Stocks. Environmental Impact of Mining. (New York: Halsted Press) 1977. p. 154.

Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1977. p. V-53.

Safety hazards for an underground shale mine are described as "safety statistics" in the Hittman report. Using data estimated in Hittman for an underground shale mine, on the average, about 34 nonfatal injuries and 0.8 deaths will occur annually in a mine excavating 66,000 TPD.¹

Health hazards for an underground shale mine are chiefly associated with worker exposure to shale dust, raw shale, and toxic gases. Shale dust and raw shale contain silica, inorganic salts, toxic metals, and some toxic organics. Free silica in the dust is a recognized hazard resulting in occupational silicosis. Conflicting results have been obtained in analyses of oil shale dust for free crystalline (alpha-quartz) silica. While some results have indicated approximately 10% silica in oil shale, one analysis has found no free silica in dust particles in the respirable size range.²

Included among the toxic organics in shale dust and raw shale are those compounds shown in Table 4-29. All of the compounds in Table 4-29 are known or suspected animal carcinogens, and may be carcinogenic to man. However, the concentrations of these compounds encountered by mine workers have not yet been determined.

Gases produced during mining operations have been previously described in Section 4.5.1.3a. Worker exposure to those gases has not been delineated.

¹Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supplied by Emerging Technologies. Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Prepared for Council on Environmental Quality, National Science Foundation, and Environmental Protection Agency. Contract EQC 308. Columbia, Maryland. May 1974.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisors. February 1977. p. V-77.

TABLE 4-29. POLYCYCLIC AROMATIC HYDROCARBONS
DETECTED IN RAW OIL SHALE

Benzo (a) pyrene (BaP)	Fluoranthene
Alkyl I (BaP)	Benz (a) anthracene
Benzo (ghi) fluoranthene	Triphenylene
Benzo (e) pyrene	Phenanthrene
Perylene	7, 12-Dimethylbenz (a) anthracene
Benzo (ghi) perylene	3-Methylcholanthrene
Anthracene	Coronene
Pyrene	Chrysene

Reference: Coomes, R.M. "Health Effects of Oil Shale Processing" Quarterly of the Colorado School of Mines 71(4): 101-123, October 1976.

4.5.1.3f Odors

Odors at an underground mine are chiefly associated with nitrogen oxides emitted during the operation of diesel equipment. Some odors associated with the presence of hydrogen sulfide may also be detected. The odors are likely to be confined to the mine site.

The inputs and outputs associated with an underground mine are summarized in Table 4-30.

TABLE 4-30. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED
WITH AN UNDERGROUND MINE PRODUCING
66,000 TPD OF CRUSHED OIL SHALE

Inputs

Manpower	
• operating	743 men
Materials and Equipment	
• jumbo drills	9
• powder trucks	5
• scaling and roof bolting rigs	5
• front end loaders	7
• haulage trucks	20
• bulldozers	10
• steel	7300 tons
Economics ^a	
• capital	\$190,000,000
• annualized operating	\$74,000,000
Water	600 gpm
Land	300-500 acres
Ancillary Energy	
• electricity	6.2×10^8 kwh/yr
• diesel fuel ^b	10,000 gal/yr

Outputs

Air Emissions	
• particulates	125 lb/hr
• hydrocarbons	54 lb/hr
• NO _x	270 lb/hr
• CO	480 lb/hr
• SO ₂	Negligible
• CO ₂	9000 lb/hr
Water Effluents	Extremely site dependent
Solid Wastes	
• from opening mine	150,000 tons
• other	Returned to mine
Noise Pollution	
• at mine boundary	Negligible
Occupational Health and Safety	
• deaths	0.8/yr
• injuries	34/yr
Odors	Confined to mine site

^a1977 dollars

^bMay be supplied by upgraded shale oil

4.5.2 Surface Mining

4.5.2.1 Technologies

Most high quality oil shale lies beneath a thick layer of overburden containing little or no kerogen. Underground mining techniques will primarily be used to extract these resources. There are some areas, however, where oil shale lies close enough to the surface to justify surface mining.¹ Prien has estimated that surface mining may be applicable to 15-20 percent of the minable oil shale resources.²

Factors affecting the suitability of oil shale surface mining are the amount of overburden that must be removed in order to mine the shale and the availability of a disposal area for the overburden.³ Prien has asserted that surface mining would be limited to areas where the overburden-to-shale ratio was less than 2.5:1.⁴

In comparison with underground mining, surface mining has several economic advantages: surface mining is capable of shale

¹Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities, Prepared for U.S. Environmental Protection Agency. Austin, Tex.: Radian Corp., September 1977, p. 5.

²Prien, Charles. Testimony before the Subcommittee on Energy, Committee on Science and Astronautics, U.S. House of Representatives, May 1974. As cited in: Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. 260.

³Schramm, L. W. "Shale Oil", Section from Bureau of Mines Bulletin No. 650, U.S. Department of the Interior. Mineral Facts and Problems. 1970. pp. 185-202.

⁴Prien, Charles, *op.cit.*

extraction at a lower cost with lower manpower requirements.¹ In addition, a greater resource extraction per unit land area is achievable. Surface mining is also inherently safer than underground mining. The main disadvantage is a high land impact associated with the initial disposal of solid wastes on the surface. Mine back-filling can begin only after many years of surface disposal at off-mine sites.²

Little experience has been gained in surface oil shale mining. However, methods used for surface mining oil shale should be comparable to those used in coal strip-mining or hard-rock open-pit mining.³ For the very lowest overburden-to-shale ratios (less than about 0.5), strip mining is the more appropriate method of resource recovery. In this type of surface mining, explosives are used to loosen overburden. The overburden is then removed from the mines by large draglines. Power shovels are used to load the rock onto trucks for transport to a disposal area.⁴

Strip mining is suitable only for oil shale deposits lying near the surface. Open pit mining is more appropriate for deeper

¹Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supplied by Emerging Technologies, Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Prepared for Council on Environmental Quality, National Science Foundation and Environmental Protection Agency. Contract EQC 308. Columbia, Maryland. May 1974.

²Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

³Conkle, Nick, et al. Environmental Considerations for Oil Shale Development. Battelle Columbus Laboratories. Prepared for U.S. Environmental Protection Agency. October 1974. p. 15.

⁴Dickson, E. M, et al. Synthetic Liquid Fuels Development: Assessment of Critical Factors, Volume II - Analysis, Prepared for U.S. ERDA and U.S. Environmental Protection Agency. ERDA 76-129/2. Stanford Research Institute. pp. 458-460.

deposits. Since deposits are most often found beneath thick overburdens, surface mining will likely develop via open pit mining.¹ The following discussion emphasizes the open pit mining technique.

Only one oil shale development specified surface mining of the shale deposit. The Rio Blanco Oil Shale Project (Gulf Oil Corp. and Standard Oil Co.) originally planned for an open-pit mine/processing development producing 56,000 barrels of shale oil per day. The developers submitted a Detailed Development Plan to the Area Oil Shale Office in March 1976. Revised development plans have rejected the surface mining/processing scheme in favor of an in-situ development.^{2,3}

Overburden at potential surface mining sites ranges from 100-800 feet in depth, averaging approximately 450 feet. Due to the required mine depth, several bench levels must be provided to develop sufficient working forces to meet production rates, as shown in Figure 4-8. An average mine slope of 45° with a working slope of 35° is typical.⁴

¹Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

²Rio Blanco Oil Shale Project. Detailed Development Plan for Oil Shale Tract C-a, Prepared for Area Oil Shale Supervisor. March 1976. As cited in: Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. TRW Environmental Engineering Division and Denver Research Institute. June 1976. pp. 48-50.

³Gulf Oil Corp. and Standard Oil Co. Revised Detailed Development Plan for Oil Shale Tract C-a, Prepared for Area Oil Shale Supervisor, 3 Volumes. May 1977.

⁴U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program, 6 Volumes. Washington, D.C.: 1973.

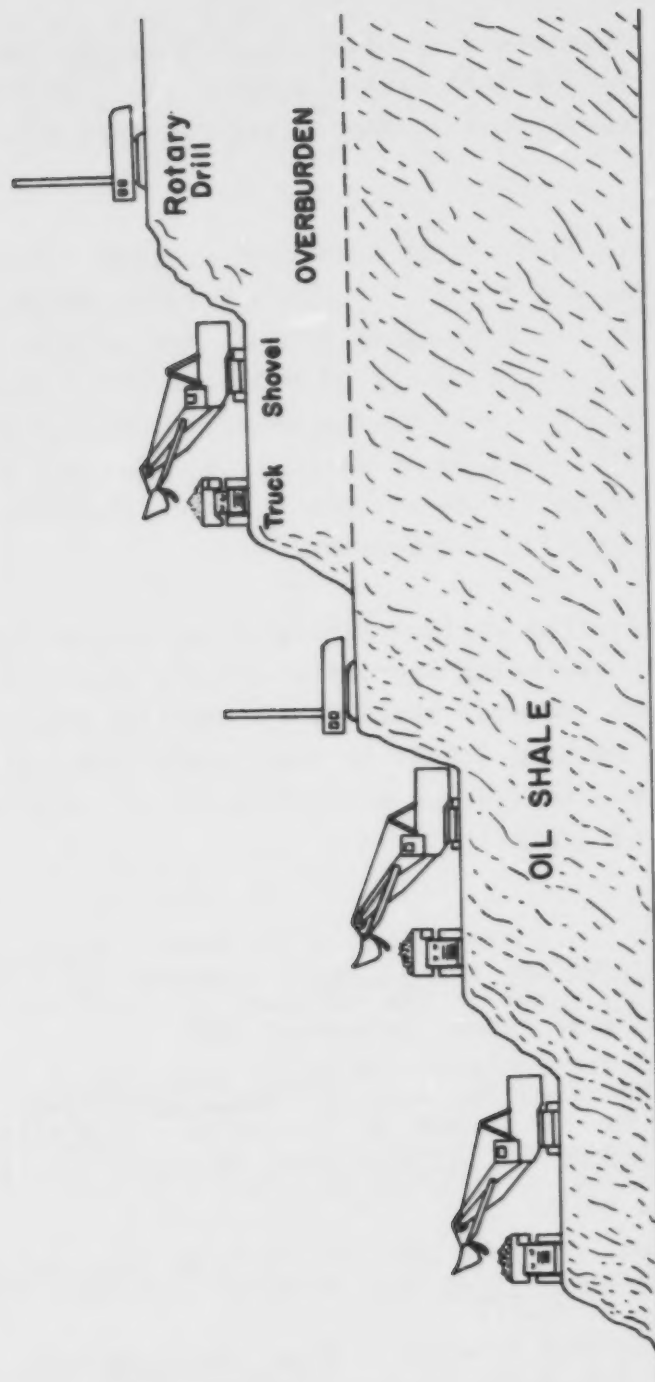


Figure 4-8. Hypothetical Open Pit Oil Shale Mine.

Source: National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee. U.S. Energy Outlook: An Initial Appraisal by the Oil Shale Task Group, 1971-1985, Washington, D.C., NPC.

Note: Not drawn to scale.

The steps involved in the surface mining of oil shale include topsoil removal and storage; overburden drilling, blasting, and removal; and oil shale drilling, blasting, and extraction. These steps resemble those for coal surface mining; however, the pit is much deeper for oil shale surface mining. Oil shale is also considerably harder than coal.¹

Overburden and shale are extracted by drilling and blasting. Blasted raw shale is loaded by large shovels (usually electrically-powered) into diesel trucks having capacities of up to 120 tons. The raw shale is then hauled to primary crushers in the pit. Road graders and water trucks are required to maintain hard roads.²

Shale from the primary crusher is removed from the mine by conveyor to secondary crushing and screening facilities. The secondary crushing and screening facilities may be located at the shale processing plant.³ Crushing operations have been previously described in Section 4.5.1.1.

Both the safety of the pit and economics of open pit mining are highly dependent upon the steepness of the side slopes that can be maintained in the pit. If the slope stability cannot be maintained at a fairly steep angle, hazardous slides may occur.

¹Colley, J. D., W. A. Gathman, and M. L. Owen, Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

²Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976.

³Colley, J. D., W. A. Gathman, and M. L. Owen, *op.cit.*, p. 6.

If it is necessary to maintain the slope at low angles to avoid slides, the cost of removing overburden may prohibit the surface mining of the shale deposit.¹

4.5.2.2 Input Requirements

This section reports inputs required for the operation and maintenance of a surface oil shale mine. Since little experience has been achieved in surface oil shale mining, the various inputs should be interpreted as preliminary estimates. The various input requirements are based on data from a variety of sources.

The inputs described in this section are representative of an oil shale surface mining/processing facility producing 50,000 barrels of shale oil per day.

4.5.2.2a Manpower

Employment projections for a surface mining/processing facility were estimated in the original DDP for Oil Shale Tract C-a. On tract C-a, approximately 56,000 barrels of oil were to be produced from 120,000 tons of shale.² Manpower required to operate the entire mining/processing facility were estimated at 1100. The number of personnel at the height of construction was estimated to be 2200.³ If the processing facility required

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency, Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976.

²The mined shale had an average oil content of about 22 gal/ton.

³Rio Blanco Oil Shale Project. Detailed Development Plan for Oil Shale Tract C-a, Prepared for Area Oil Shale Supervisor. March 1976. As cited in: Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. TRW Environmental Engineering Division and Denver Research Institute. June 1976. pp. 48-50.

about 430 men¹ (see Section 4.6.1.3, Surface Retorting), then the manpower required to operate mining and crushing equipment amounted to about 670.

Fewer personnel are required for the mining and crushing of richer shale deposits. For example, for a shale deposit having an average oil content of 35 gal/ton, a 50,000 BPD processing facility can be supplied by a mine producing 66,000 tons of shale per day. (This production equals the demand of the processing plant, assuming that the plant operates at approximately 90 percent capacity on a yearly basis.)² Using scaling factors developed for the Battelle Oil Shale Model, manpower requirements for a 66,000 TPD facility amount to about 410.^{3,4}

Accurate skills breakdowns of construction and operation personnel are unavailable.

4.5.2.2b Materials and Equipment

Detailed materials and equipment requirements have not been prepared by any potential surface mine developers. However, the Federal Energy Administration has estimated equipment requirements for a surface mine excavating 140,000 TPD oil shale. While the

¹Ashland Oil, Inc. and Shell Oil. Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-6, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-10.

²Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

³Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. D-34.

⁴The labor scaling factor in line 6 of Table D-2 (in the FEA report) was used in this analysis: a doubling of capacity increases labor requirements by 62.5%.

data in the FEA report are now somewhat outdated, a mine removing 66,000 TPD may be assumed to require about half of the equipment required for the 140,000 TPD mine. The equipment list given in Table 4-31 is not complete and may be based on outdated information. Crushing and screening apparatus are omitted from the equipment list.¹

As estimated for use in a Battelle computer model, steel requirements during plant construction amount to:

Crushing, Screening, and Briquetting	3700 tons
Mining	4700 tons

These values were extrapolated from data in the FEA report and may not be accurate.

4.5.2.2c Economics

Current costs estimates for a surface mining/crushing operation are unavailable. Battelle made preliminary estimates of surface mining costs in the FEA's Project Independence Blueprint report on the potential development of oil shale. A surface mine extracting 140,000 tons of oil shale per day had the following costs (mid-1974 dollars):

Capital	\$101,000,000
Operating	\$ 39,000,000

(Costs for sizing operations were not included in the costs for mining operations.)²

¹Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. H-179.

²*Ibid.*, p. H-173.

TABLE 4-31. ESTIMATED EQUIPMENT LIST FOR A SURFACE MINE EXCAVATING
66,000 TPD OIL SHALE

Equipment	Description	Number Required	Capacity	HP
Loading Shovels	Electric Drive	4	18 yd ³	--
Trucks	Diesel Drive	12	120 ton	800
Primary Drills	Rotary Electric	4	--	500
Road Graders	Diesel Drive	3	--	--
Bulldozers	Diesel Drive	3	--	270
Mobile Crane	--	1	45 ton	--
Water Trucks	Diesel Drive	2	5000 gal	300
Front-end Loaders	Diesel Drive	2	6 yd ³	325
Mechanic Trucks	Diesel Drive	2	--	165
Lubrication Truck	Diesel Drive	1	--	165
Welding Truck	Gasoline Drive	2	--	165
Utility Truck	Gasoline Drive	1	--	110
Fuel Truck	Diesel Drive	1	--	--
Explosives Truck	Gasoline Drive	1	--	120
Fork Lift	Gasoline Motor	1	--	--
Tire Truck	Gasoline Drive	1	--	120
Ambulance	Gasoline Drive	1	--	80

Note: Actual equipment list for surface mining may differ substantially from the above list.

Source:

Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints, Federal Energy Administration. November 1974. p. H-179.

Current estimates of the capital costs of surface mining/crushing cannot be accurately determined from the literature. According to Battelle's early estimates, the capital costs of underground mining are exceeded by the capital costs of surface mining.^{1,2} If we accept published data for underground mining, then the capital costs for a 66,000 TPD surface shale mine are expected to exceed \$190,000,000 (1977 dollars). (See Section 4.5.1, Underground Mining.)^{3,4}

The U.S. Bureau of Mines contracted Sun Oil Company to perform a technical and economic study on the open pit mining of deep shale oil deposits. Preliminary cost data for surface mining operations were reported in the Phase I report to the U.S. Bureau of Mines.⁵ These data are presented in Table 4-32. The costs include both fixed and operating cost components for various surface mining operations.

¹Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. H-172.

²This statement is based on a comparison of the costs for 100,000 BPD underground and surface mining facilities. At the 100,000 BPD production level, capital costs for underground mining are only about half of those for surface mining. Crushing plant capital costs are the same for both mining methods. At other production rates, the surface mine may have costs more nearly akin to those for the underground mine.

³Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. p. I-22.

⁴The reported capital cost includes costs for mining, crushing, and processed shale disposal.

⁵Banks, C. E., et al. Technical and Economic Study of an Integrated Single Pass Mining System for Open Pit Mining of Deep Oil Shale Deposits, Phase I Report. Sun Oil Company. Prepared for U.S. Bureau of Mines. BuMines OFR 22-76.

TABLE 4- 32. UNIT ANNUALIZED COSTS FOR THE OPEN PIT
MINING OF OIL SHALE

Activity	Mid-1974	1977
Drilling		
Overburden	\$0.013/ton	\$0.016/ton
Oil Shale	\$0.016/ton	\$0.019/ton
Blasting		
Overburden	\$0.063/ton	\$0.076/ton
Oil Shale	\$0.068/ton	\$0.082/ton
Loading		
Overburden	\$0.064/ton	\$0.077/ton
Oil Shale	\$0.057/ton	\$0.068/ton
Haulage		
Trucks	\$0.11/ton-mile	\$0.13/ton-mile
Conveyors	\$0.05/ton-mile	\$0.06/ton-mile
Primary Crushing	\$.059/ton	\$.071/ton
Waste Disposal		
Spreader-Stripper	\$.022/ton	\$.026/ton
Mine Dewatering	\$.00035/gal	\$.00042/gal

Note: Costs are typical costs encountered at open pit mines; when range of costs reported in reference, costs in table are averages. The indexing factor to 1977 is 1.2. Costs for miscellaneous equipment are not reported on a usable basis.

Source:

Banks, C. E., et al. Technical and Economic Study of an Integrated Single Pass Mining System for Open Pit Mining of Deep Oil Shale Deposits, Phase I Report. Sun Oil Company. Prepared for U.S. Bureau of Mines. BU Mines OFR 22-76. pp. 5-13, 26, 43-44, 62, 73-75, 93, 99, 104.

Preliminary estimates of the annualized operating costs for a surface mine producing 66,000 TPD are shown in Table 4-33. These costs have been constructed from the labor, power, and fuel requirements described in this report. Other costs are estimated as percentages of the capital or labor costs. Total operating costs are shown in Table 4-33 as \$61,000,000, and are based on preliminary incomplete data.^{1,2}

4.5.2.2d Water

Most of the water required for a surface mining operation is needed for dust control. The FEA has estimated that similar-sized surface and underground mines have similar water requirements.³ Mining water requirements for a 66,000 TPD shale surface mine are estimated to be 450 gpm (730 acre-ft/year).^{4,5} An additional 150 gpm (240 acre-ft/year) are required for dust control for primary crushing and coarse ore storage.⁶ Total water usage for mining and crushing amounts to 600 gpm (970 acre-ft/year).

¹Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976.

³Interagency Task Force on Oil Shale, *op.cit.*, p. 154.

⁴Ashland Oil, Inc. and Shell Oil Co., *op.cit.*, p. IV-22.

⁵This quantity assumes that surface mining and underground mining have similar water requirements.

⁶Ashland Oil, Inc. and Shell Oil Co., *op.cit.*, p. IV-22.

TABLE 4-33. PRELIMINARY ANNUALIZED COSTS ESTIMATES FOR
THE OPEN PIT MINING OF OIL SHALE^{a, b}

Component	Cost
Direct Costs	
Personnel ^c	\$ 6,600,000
Operating Supplies ^d	2,500,000
Maintenance Materials ^e	1,500,000
Utilities	
Electricity ^f	11,000,000
Water ^g	—
Diesel Fuel ^h	4,000,000
Fixed Costs	
Depreciation ⁱ	25,000,000
Taxes and Insurance ^j	7,500,000
Plant Overhead ^k	
	<u>3,300,000</u>
Total	\$ 61,000,000 \$3.34/bbl

^aShale oil production capacity of 50,000 BPD; shale excavation requirement of 66,000 TPD; overburden excavation requirements of 72,000 TPD.

^bCosts are in 1977 dollars and include only those costs directly attributed to mining and crushing operations.

^cCalculated @ \$15,000/man/year for labor, \$20,000/man/year for supervision.

^dCalculated @ 1% of the fixed capital costs which are conservatively estimated at \$250,000,000.

^eCalculated @ 100% of maintenance labor.

^fCalculated @ \$0.04/kwh.

^gWater requirements are met by mine dewatering.

^hCalculated @ \$0.50/gal.

ⁱCalculated @ 10% of fixed capital.

^jCalculated @ 3% of fixed capital.

^kCalculated @ 50% of total labor costs.

Note: Rates for calculating fixed costs, plant overhead, and costs for operating supplies and maintenance materials are largely based on Peters, M. S. and K. D. Timmerhaus. Plant Design and Economics for Chemical Engineers, 2nd. Ed. (New York: McGraw-Hill Book Co., 1968), pp. 132-141.

Source: Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974.

Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume 1, Prepared for Area Oil Shale Supervisor. February 1976.

Consumptive uses during construction include dust control, fill compaction, and personnel uses. Quantities for these uses amount to 500-700 (800-1100 acre-ft/year) during the construction of an underground mine.¹ Similar quantities can probably be anticipated for a surface mine.

4.5.2.2e Land

The Federal Energy Administration has estimated the magnitude of surface disturbances associated with a surface mining operation. These are reported in Table 4-34.² Areas required for the disposal of processed shale are associated with shale processing and are discussed in Section 4.6.1.2.

4.5.2.2f Ancillary Energy

Ancillary energy requirements for surface mining/crushing operations are tabulated in Table 4-35. The energy recovery ratio is determined to be 0.99.

4.5.2.3 Outputs

This section reports the various outputs associated with the operation of a surface oil shale mine. However, no information is available from actual surface shale mining operations. Discussions of air emissions, water effluents, solid wastes, noise

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume 1, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-62.

²Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. 139.

TABLE 4-34. AVERAGE OF SURFACE DISTURBANCES ASSOCIATED
WITH A 66,000 TPD SURFACE MINING OPERATION^a

Mine Development	15-45 acres per year
Permanent disposal of overburden	500 acres (total) ^b
Temporary storage of raw shale	50-100 acres (total)
Water in dams	150-270 acres (total) ^c
Other	90-300 acres (total) ^d

^aEstimates are scaled from data in FEA report; area required for shale crushing is not separable from the area reported for shale processing in the FEA report.

^bArea required is dependent on the thicknesses of the overburden and oil shale at the site. Acres shown are for a Piceance Creek Basin site, with 550 feet of overburden and 450 feet of 30 gal/ton shale.

^cWater storage for entire mining/processing complex is based on requirements for an underground mine. The land areas required for water storage or ponding vary from site to site. Most developers use natural terrain to create large reservoirs.

^dRequired areas include access roads, power and transmission facilities, water lines, natural gas and oil pipelines for entire mining/processing complex. A 60 ft right-of-way for roads requires a surface area of about 8 acres per mile. Utility and pipeline corridors require 2.4 acres per mile.

^eAreas required for processed shale disposal are discussed in Section 4.6.1.

Source:

Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. p. 39.

Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-9.

TABLE 4-35. ANCILLARY ENERGY REQUIREMENTS FOR SURFACE SHALE MINING AND CRUSHING^a

Category	Power or Fuel Requirements	Energy Usage
Electricity		
Pit Crushing and Conveying	5500 hp	2.9×10^7 kwh/year ^b
Dewatering ^c	4000 hp	2.6×10^7 kwh/year ^d
Loading	---	2.0×10^7 kwh/year ^e
Crushing and Screening	---	1.5×10^8 kwh/year
General Services	---	4×10^7 kwh/year
TOTAL		2.7×10^8 kwh/year ^f
Diesel Fuel	22,000 gal/d	1.1×10^{11} Btu/year ^g

^aShale oil production capacity of 50,000 BPD; overburden excavation requirement of 72,000 TPD; shale excavation requirement of 66,000 TPD.

^bAssumes mine operates 350 days/year, 3 shifts/day, 6.5 hours (eff.)/shift.

^cDewatering requirements vary from site to site and are different for different mining techniques. Value is that reported by Occidental (see References).

^dAssumes dewatering requirements occur 365 days/year.

^eLarge electric quarry shovels with energy consumption of 0.6 kwh/cy. Shovels load overburden and raw shale.

^fFigure represents electricity directly used in mining. Gross power plant energy requirements can be estimated by using power plant heat rate of 9750 Btu/kwh (power generation efficiency of 35%).

^gAssumes mine operates 350 days/year; heating value for diesel fuel of 140,000 Btu/gal.

Sources:

Colley, J. D. W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

Ashland Oil, Inc. and Shell Oil Company. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. p. IV-28.

Ashland Oil, Inc. and Occidental Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b, Prepared for Area Oil Shale Supervisor. February 1977, p. III-39.

Hittman Associates, Inc. Environmental Impacts, Efficiency and Cost of Energy Supplied by Emerging Technologies. Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Prepared for Council on Environmental Quality, National Science Foundation, and Environmental Protection Agency. Contract EQC 308. Columbia, Maryland. May 1974.

pollution, occupational health and safety, and odors are based on information from a variety of sources other than actual mines.

The surface mine extracts 66,000 TPD oil shale and 72,000 TPD overburden. This mine production is sufficient to supply a 50,000 BPD processing facility with shale having an average oil content of 30 gal/ton. (The production equals the demand of the processing plant, assuming that the plant operates at approximately 90 percent capacity on a yearly basis.)¹

4.5.2.3a Air Emissions

Air emission sources associated with the surface mining facilities include excavation blasting, road dust from transportation of oil shale and overburden, combustion emissions from diesel-powered equipment, primary and secondary crushing operations, and wind blown dust. Air emissions from crushing operations have been previously described in Section 4.5.1.3 and are not discussed in this section. Estimates of the remaining air emissions are summarized in Table 4-36 and are described below. The estimates do not include the effect of control measures beyond basic requirements. The basic requirements assumed include hard surfacing major mine access roads and periodic water spraying of secondary roads as conditions require.²

Primary sources of information for this section include the Environmental Assessment for a Proposed Coal Gasification

¹Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

²*Ibid.*, p. 6, 12.

TABLE 4-36. ATMOSPHERIC EMISSIONS FROM OIL SHALE SURFACE MINING

Basis: 66,000 TPD oil shale mined

Operation	Particulates	SO ₂	Emissions (lbs/hr)		
			NO _x	Hydrocarbons	CO ₂
Wind erosion	4				
Topsoil removal and storage losses	1				
Drilling	9.5				
Blasting of overburden	70	Some			
Blasting of oil shale	8.5	Some			
Overburden excavation	210				
Mining roads	120				
Diesel equipment	27	59	800	92	480
TOTAL	450	59	800	92	480
					19,000 ^a
					19,000 ^a

^a Estimated from diesel fuel requirement; assumes all carbon compounds in fuel combusted to CO₂.

Sources:

Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

Wyoming Coal Gas Company and Rochelle Coal Company. Applicants' Environmental Assessment for a Proposed Coal Gasification Project, Campbell and Converse Counties, Wyoming. October 1974.

U.S. Department of the Interior, Bureau of Reclamation, Upper Colorado Region, El Paso Gasification Project, San Juan County, NM. Draft Environmental Statement. DES-74-77, 1974. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors, 2nd Ed. AP-42. Research Triangle Park, N.C. 1973.

Hittman Associates, Inc. Environmental Impacts, Efficiency and Cost of Energy Supplied by Emerging Technologies. Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Prepared for Council on Environmental Quality, National Science Foundation, and Environmental Protection Agency. Contract EPC 308. Columbia, Maryland. May 1974.

Project by Wyoming Coal Gas Co. and Rochelle Coal Co. as prepared by SERNCO,¹ and the Draft Environmental Statement for the El Paso Coal Gasification Project.²

Wind erosion results in the discharge of particulates from the exposed mine areas. Using a wind erosion equation developed by PEDCo-Environmental, an emission factor of 0.60 metric tons/acre-year is calculated. Assuming 30 acres per year are disturbed during mining, approximately 4 lbs/hr of particulates are emitted.^{3,4}

Topsoil removal and its storage is the first operation in overburden excavation. SERNCO estimated that topsoil removal discharges roughly 76 kg/acre-yr of topsoil disturbed. This amounts to less than 1 lb/hr of dust emitted to the air from this operation, assuming 30 acres per year are disturbed due to mine development.^{5,6,7}

¹Wyoming Coal Gas Company and Rochelle Coal Company. Applicants' Environmental Assessment for a Proposed Coal Gasification Project, Campbell and Converse Counties, Wyoming. October 1974.

²U.S. Department of the Interior, Bureau of Reclamation, Upper Colorado Region. El Paso Gasification Project, San Juan County, NM, Draft Environmental Statement. DES-74-77, 1974.

³Cowherd, Charlten, Jr., et al. Development of Emission Factors for Fugitive Dust Sources, Final Report. EPA-450/3-74-037, Contract No. 68-02-0619. Kansas City, Mo.: Midwest Research Institute, June 1974.

⁴U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program, 6 Vols. Washington, D.C.: 1973

⁵*Ibid.*

⁶Wyoming Coal Gas Company and Rochelle Coal Company, *op.cit.*

⁷Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities, Prepared for U.S. Environmental Protection Agency. Austin, Tex.: Radian Corp., September 1977, p. 13.

Blast hole preparation by drilling releases noticeable amounts of particulates during overburden removal. Scaling the quantity given by SERNCO for overburden drilling emissions to the overburden removal rate in this analysis, it is estimated that 9.5 lbs/hr of particulates are emitted.^{1,2}

The blasting of the overburden discharges significant quantities of dirt and dust into the air; however, this operation occurs only periodically. Scaling the estimates by SERNCO for overburden blasting, roughly 70 lbs/hr of particulates less than 10 μ in diameter are discharged to the atmosphere. This number is based on the assumption that the large diameter particles settle out in the immediate vicinity of the mine.^{3,4}

Following blasting, the overburden is loaded for removal from the pit area. This phase of mining is the largest single source of particulates in the extraction operation. SERNCO estimates that approximately 0.035 kg of dust is emitted per metric ton of overburden removed. Assuming a daily removal rate of 72,000 TPD, the resulting emissions will be about 210 lb/hr.^{5,6}

¹Wyoming Coal Gas Company and Rochelle Coal Company. Applicants' Environmental Assessment for a Proposed Coal Gasification Project, Campbell and Converse Counties, Wyoming. October 1974.

²Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

³Wyoming Coal Gas Company and Rochelle Coal Company, *op.cit.*

⁴Colley, J. D., W. A. Gathman, and M. L. Owen, *op.cit.*

⁵Wyoming Coal Gas Company and Rochelle Coal Company, *op.cit.*

⁶Colley, J. D., W. A. Gathman, and M. L. Owen, *op.cit.*, p. 14.

The fragmenting of the oil shale by blasting periodically releases some dust to the air. Assuming the same amount of dust is emitted for the blasting of the oil shale as for coal (0.0016 kg/MT of material mined), then 9.6 lbs/hr of dust are emitted.^{1, 2}

The diesel-powered vehicles operating in the pit emit significant quantities of pollutants. The equipment consumes approximately 22,000 gal/day of diesel fuel (scaled value obtained from Hittman Report).³ The emissions were determined by applying EPA emission factors for heavy duty diesel engines.^{4, 5}

Hauling the extracted shale and overburden on mine roads results in the dispersion of dust from both payloads and road surfaces. Scaling emission estimates reported by SERNCO for coal mine road dust give a total particulate discharge rate of roughly 120 lbs/hr for the hauling of the oil shale and overburden.^{6, 7}

¹Wyoming Coal Gas Company and Rochelle Coal Company. Applicants' Environmental Assessment for a Proposed Coal Gasification Project, Campbell and Converse Counties, Wyoming. October 1974.

²Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

³Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supplied by Emerging Technologies. Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Prepared for Council on Environmental Quality, National Science Foundation, and Environmental Protection Agency. Contract EQC 308. Columbia, Maryland. May 1974.

⁴Environmental Protection Agency. Compilation of Air Pollutant Emission Factors, 2nd Ed. AP-42. Research Triangle Park, N.C.: May 1973.

⁵Colley, J. D., W. A. Gathman, and M. L. Owen, *op.cit.*

⁶Wyoming Coal Gas Company and Rochelle Company, *op.cit.*

⁷Colley, J. D., W. A. Gathman, and M. L. Owen, *op.cit.*

4.5.2.3b Water Effluents

Potential water effluents from mining operations include: excess minewater, runoff from raw shale stockpiles, and sanitary wastewaters. Volumes of these potential water effluents have not been estimated. Quantities and qualities of excess minewater and runoffs are largely dependent on the site of the mine development. Characteristics and disposal of these water effluents have been discussed in Section 4.5.1.3.

4.5.2.3c Solid Wastes

A major environmental problem associated with surface mining is solids disposal. Initially, overburden must be hauled off-site to some containment area. Only after mined-out areas of the pit become available can back filling begin. This is expected to be a long time period: up to 30 years for open pit mines, one year for strip mines. Since solid waste cannot be disposed of underground, the land impact associated with surface mining is higher than with underground mining. For a surface mine producing 66,000 TPD of raw shale, approximately 71,000 TPD of overburden must be disposed of.¹ The wasted material resembles the natural talus material and its disposal does not have a severe impact on the visual or aesthetic quality of the site.

Solid wastes generated from shale sizing operations are discussed in Section 4.5.1.3. Water treatment sludges result from upgrading minewater for processing and are discussed in Section 4.6.

¹Colley, J. D., W. A. Gathman, and M. L. Owen, Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, Tex.: Radian Corporation, September 1977.

4.5.2.3d Noise

Noise at surface mines originates from normal mining operations. Typical levels of sound levels at worker positions are shown in Table 4-37.

4.5.2.3e Occupational Health and Safety

Health and safety hazards associated with surface shale mining have not been extensively examined. Safety hazards for a surface shale mine are described as "safety statistics" in the Hittman report. Using data estimated in Hittman for an underground shale mine, on the average, about 10 nonfatal injuries and 0.2 deaths will occur annually in mining accidents at a mine excavating 66,000 TPD.¹ Health hazards for a surface mine are chiefly associated with worker exposure to shale dust, raw shale, and toxic gases. These hazards have been discussed in Section 4.5.1.3.

4.5.2.3f Odors

Odors at a shale surface mine are chiefly associated with nitrogen oxides emitted during the operation of diesel equipment. Some odors associated with the presence of hydrogen sulfide may also be detected. The odors are likely to be confined to the mine site.

The inputs and outputs associated with a surface mine are summarized in Table 4-38.

¹Hittman Associates, Inc., Environmental Impacts, Efficiency, and Cost of Energy Supplied by Emerging Technologies. Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Prepared for Council on Environmental Quality, National Science Foundation, and Environmental Protection Agency. Contract EQC 308. Columbia, Maryland. May 1974.

TABLE 4-37. NOISE LEVELS ENCOUNTERED BY MINE WORKERS

Noise Source	Sound Level, dBA
Diesel Trucks	74-109
Electric Shovels	78-101
Graders	76-104
Dozers	84-107
Rotary Drills	72-100
Front-end Loaders	83-101
Scrapers	92-104
Belted Conveyor	75-85
Primary Crushing	72-111

Source: Down, C. G. and J. Stocks. Environmental Impact of Mining (New York: Halsted Press) 1977. p. 154.

U.S. Department of the Interior. Noise Control Proceedings: Bureau of Mines Technology Transfer Seminar, Pittsburgh, PA. January 22, 1975. pp. 6, 95.

TABLE 4-38. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED
WITH A SURFACE MINE PRODUCING
66,000 TPD OF CRUSHED OIL SHALE

Inputs

Manpower	
• operating	410 men
Materials and Equipment	
• loading shovels	4
• trucks	12
• drills	4
• bulldozers	3
• front-end loaders	2
• explosives truck	1
• steel	7400 tons
Economics ^a	
• capital	Over \$200,000,000
• annualized operating	\$61,000,000
Water	600 gpm
Land	800-1200 acres
Ancillary Energy	
• electricity	2.7×10^8 kwh/yr
• diesel fuel ^b	22,000 gal/d

Outputs

Air Emissions	
• particulates	510 lb/hr
• hydrocarbons	92 lb/hr
• NO _x	800 lb/hr
• CO	480 lb/hr
• SO ₂	59 lb/hr
• CO ₂	19,000 lb/hr
Water Effluents	Extremely site dependent
Solid Wastes	
• overburden	71,000 TPD
Noise	
• at mine boundary	Negligible
Occupational Health and Safety	
• deaths	0.2/yr
• injuries	10/yr
Odors	Confined to mine site

^a1977 dollars

^bMay be supplied by upgraded shale oil

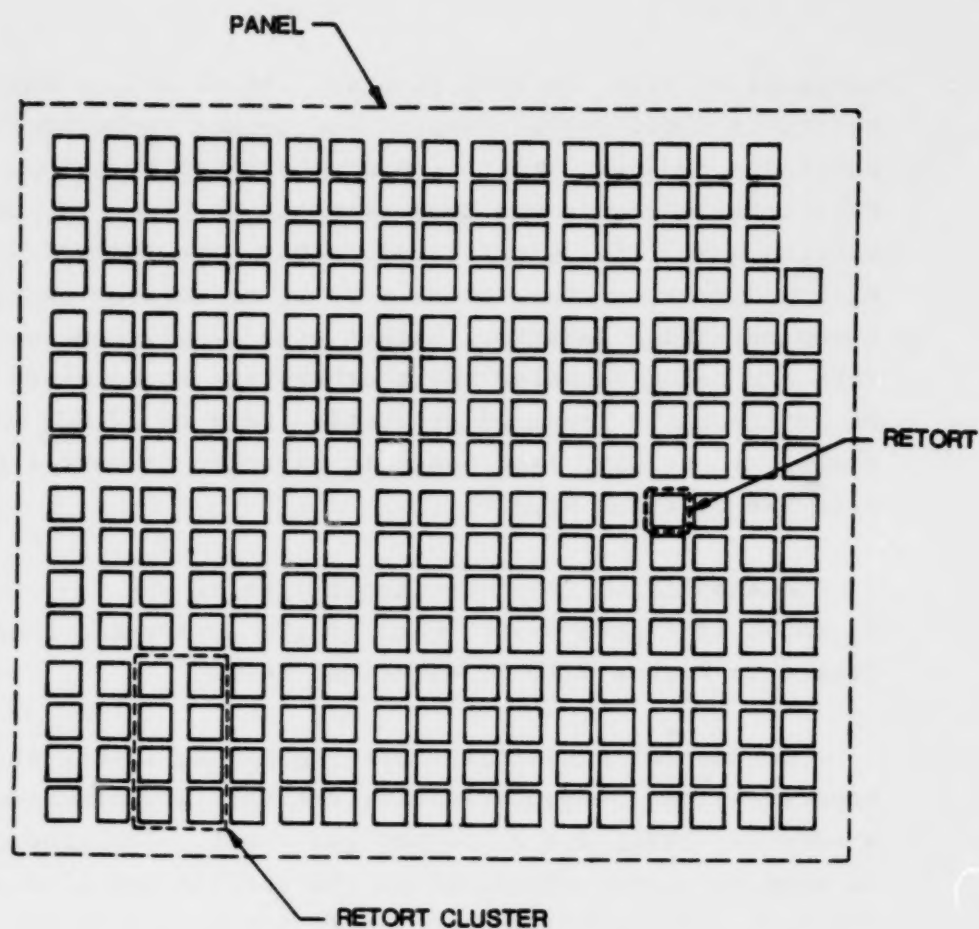
4.5.3 Mining for In-Situ Processing

4.5.3.1 Technologies

The various, proposed in-situ oil shale processes are largely differentiated by mining requirements or techniques. True in-situ processes do not require any mining of the oil shale deposits. Modified in-situ processes require underground mining of a portion of the oil shale, followed by fracturing of the remaining shale to form an underground rubble-filled retort. Discussions of true in-situ processes are presented in Section 4.6.2.1, In-Situ Retorting Technologies. Mining operations required in modified in-situ processes are discussed in this section. Retorting operations in modified in-situ processes are discussed in Section 4.6.2.1.

Occidental Oil Shale, Inc. and the Lawrence Livermore Laboratory at the University of California are developing modified in-situ processes on federal oil shale lease tracts C-a and C-b. Occidental's process has been most extensively developed, with commercial operations (57,000 barrels of shale oil per day) expected to commence on tract C-b in 1983. Lawrence Livermore Laboratory's process for Rubble In-Situ Extraction (RISE) of shale oil is being developed for use on tract C-a. Commercial operation of the RISE process is likely to commence in 1986. Descriptions of the mining procedures of both processes are found below. Occidental's process is the more developed of the two processes, and is described in greater detail.

As envisioned by Occidental, an in-situ complex is mined by developing successive geographic areas called panels. Each panel comprises groups or clusters of retorts (as shown in Figure 4-9). Occidental's preliminary plans anticipate panels composed of 32 retort clusters. The retort clusters are in turn



NOTE UNDISTURBED SHALE ZONES (PILLARS) BETWEEN RETORTS
MAY BE THICKER THAN SHOWN ON PLAN VIEW.

Figure 4-9. Plan View of Retort Arrangement.

Reference: Ashland Oil, Inc. and Occidental Oil
Shale, Inc. Modification to Detailed
Development Plan for Tract C-B. Pre-
pared for Area Oil Shale Supervisor.
February, 1977.

composed of eight in-situ retorts. About 20% of the shale in a retort is mined using classic underground techniques with the remainder blasted into the void(s) created by the mining. The rubble-filled zones are then retorted in place (as described in Section 4.6.2.1). Clusters of retorts are retorted concurrently with undisturbed shale zones serving as control partitions between operating retorts. Within each panel, some retort clusters are being retorted while others are being mined and developed. At Occidental's proposed production rate of 57,000 barrels of shale oil per day, each panel is expected to have a production lifetime of about 4 years.¹

A simplified cross-sectional view of the in-situ complex is shown in Figure 4-10. Each of the levels and shafts illustrated in Figure 4-10 is described below.

Occidental envisions accessing mining levels through three concrete-lined 34-foot-diameter shafts: a production shaft, a service shaft, and a product gas shaft. The production shaft is used to convey minewater to the surface and also serves as the main ventilation exhaust shaft for mining operations. Mined rock (or muck) is transported to the surface through the production shaft by a hoist. The production shaft is also used to convey liquid retorting products (i.e., oil and water) to the surface. Occidental's plans call for the shaft to be sunk 2100 feet to a position about 250 feet below the production level. Pumping and loading facilities are located at the foot of the shaft below the production level.²

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor. February 1977. p. III-1, III-22.

²*Ibid.*, p. III-5.

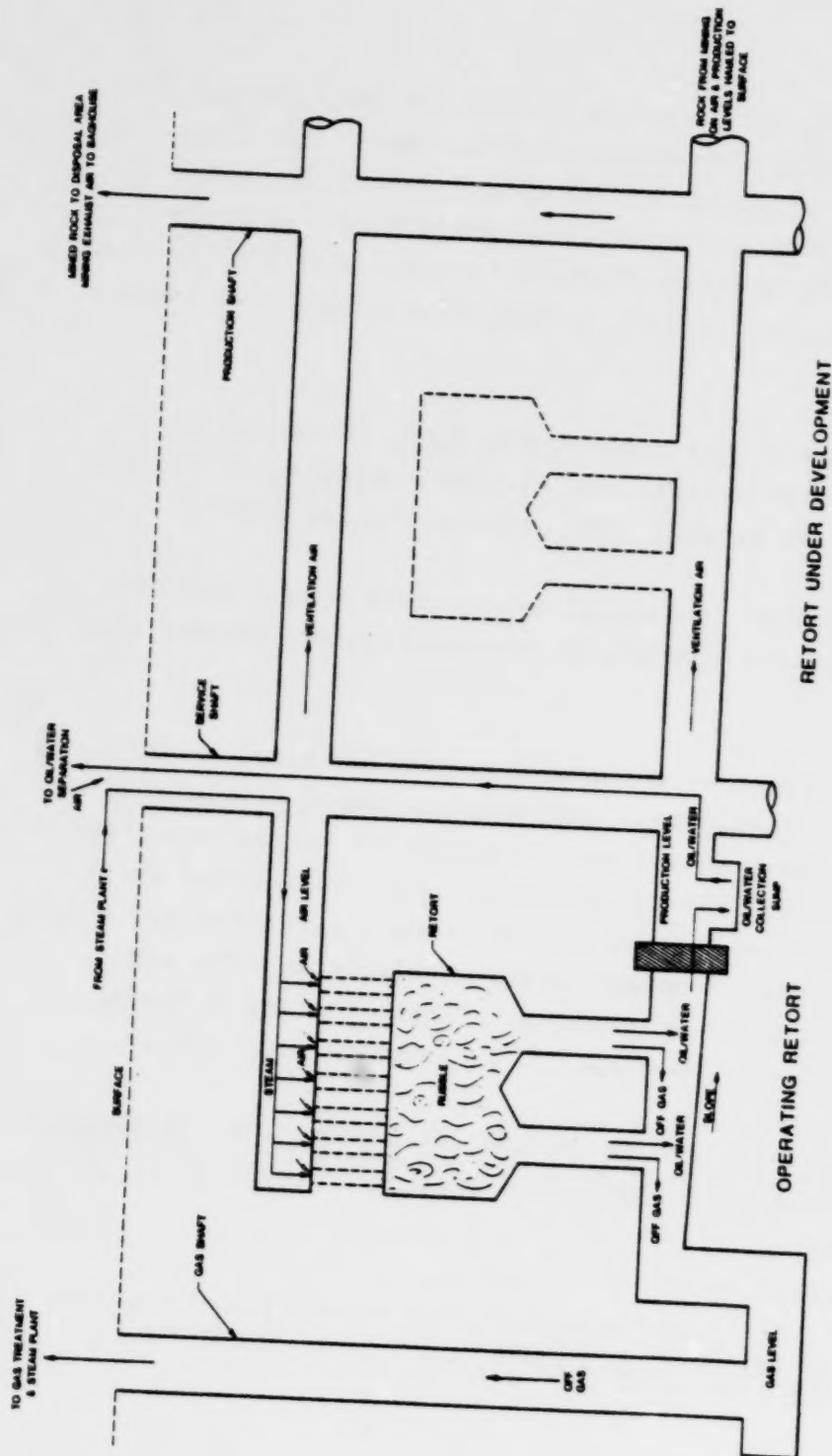


Figure 4-10. Cross-Section of In-Situ Complex: Retort Operation and Development.
 Reference: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material
 to Modified Detailed Development Plan for Oil Shale Tract C-B. Prepared
 for Area Oil Shale Supervisor. June 1977.

The service shaft serves as an intake for both process air (for retorting) and ventilation air (for mining). The shaft is also used to convey minewater and liquid retorting products to the surface. Occidental's plans for developing oil shale tract C-b call for the service shaft to be sunk 1850 feet to the production level. A hoist raises a cage for transport of heavy equipment items.¹

The sole purpose of the product gas shaft is to convey retort off gas to surface treatment and steam generation facilities. The shaft is to be sunk 1900 feet to the gas level.²

Smaller shafts used in initial retort development are used during full-scale mining operations for ventilation, escape ways and mine dewatering.³

Two retort development methods have been proposed by Occidental: vertical slot development and multiple level development. The mining levels and plan for each development scheme are shown in Figures 4-11 and 4-12.⁴ The process air level is located above the retorts and carries process air to operating retorts and mine ventilation air to mine headings under development. The air level also contains steam distribution lines, startup burners, air dampers, and related equipment for operating the retorts.

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor. February 1977. p. III-5 to 6.

²*Ibid.*, p. III-6.

³*Ibid.*, p. III-4 to 5.

⁴Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Detailed Development Plan Modifications for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor, July 21, 1977.

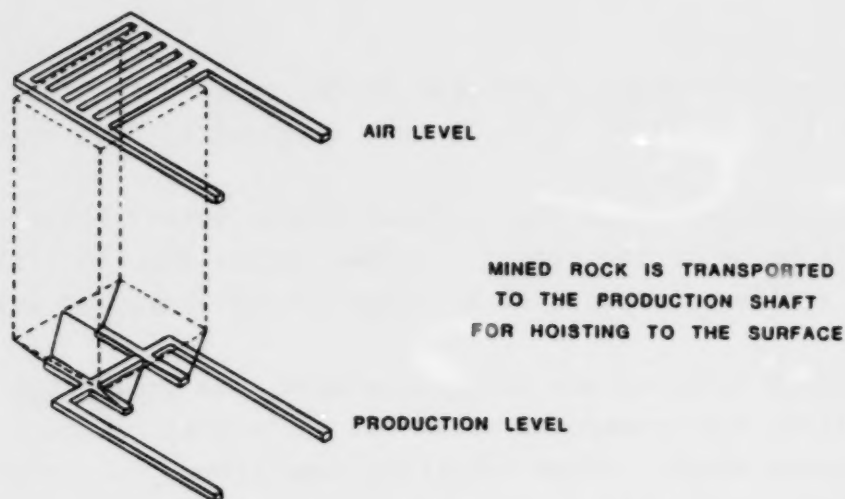


Figure 4-11. An In-Situ Retort Being Developed By The Vertical Slot Development Method.

Source: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. July 21, 1977.

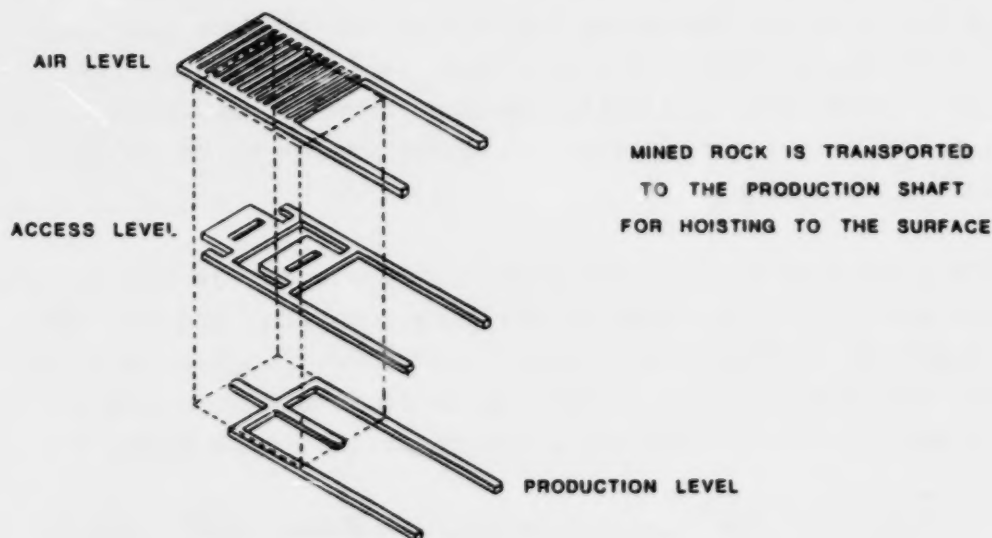


Figure 4-12. An In-Situ Retort Being Developed By The Multiple Level Development Method.

Source: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. July 21, 1977.

Occidental's development plans provide for tunnels (called drifts) on the air level to be 30 feet wide and 20 feet high.¹

Access levels within the vertical retort interval are used to evacuate voids in the retort. Access drifts (or tunnels) are generally similar and parallel to other levels above and below.²

As retort clusters are being developed, the production level receives and transports mined-out shale from the mine to the production shaft. Under retorting conditions, the lateral drifts under the retort act as conduits for product oil, water and gas. Drifts on the production level contain oil/water gathering and pumping systems and other process operating equipment. Occidental's development plans anticipate production drifts 30 feet high and 20 feet wide.³

The product gas level (shown in Figure 4-10) conveys the product gas from the operating retorts to the product gas shaft and then to the surface. The gas level is located below the production level and is totally isolated from other mining drifts. Occidental anticipates gas level drifts to be 30 feet high and 30 feet wide.⁴

The mining of the various levels proceeds by the conventional room-and-pillar mining cycle of drilling, charging the drilled face, blasting, wetting the blasted rock pile, loading, hauling, scaling, and roof bolting. Drilling is performed with large-scale electric-powered hydraulic rotary drills. The holes are

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b prepared for Area Oil Shale Supervisor, February 1977, p. III-23.

²*Ibid.*, p. III-23 to 24.

³*Ibid.*

⁴*Ibid.*, p. III-24.

then loaded with an explosive mixture (e.g., ammonium nitrate/fuel oil) and blasted into a pile of broken rock. The rock pile is wetted to minimize dust and conveyed to the production shaft. An orepass system is used to transfer rock from the upper mining level(s) to the loading pocket below the production level. All rock is then hoisted to the surface for disposal or surface retorting.¹

After the rock pile has been removed from the work area, loose rock is removed from the sides and roof of the mine by mechanical scaling equipment. The sides and floor of the mine are then wetted to control dust (if necessary).²

After the rooms within the retorts have been excavated, holes are drilled in the remainder of the shale in the retort. These holes are then loaded and blasted, thus rubbing the shale column.³ Retorts developed by the vertical slot method are 150-feet by 405-feet by 290-feet high. Retorts developed by the multiple level method are 200-feet square by 310-feet high. Occidental's choice of a retort development scheme is apparently still under study.⁴

The RISE process is conceptually similar to the process envisioned by Occidental. As in the OXY process, about 20 percent of the oil shale is mined underground. Retorts formed by

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b prepared for Area Oil Shale Supervisor, February 1977, p. III-26.

²*Ibid.*

³*Ibid.*, p. III-26 to 27.

⁴Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor, July 21, 1977.

the mining are expected to be 750 feet high with a base 150 by 300 feet. The rubble column is created by a continuous mining process using a modified sublevel caving technique (as shown in Figure 4-13). This procedure presumably prepares rubble of more uniform size than the OXY process. The proposed mining technique also permits continual measurement of rubble size. Obviously, a thick oil shale formation is required for this process. No field testing of the RISE process has yet been performed.^{1,2}

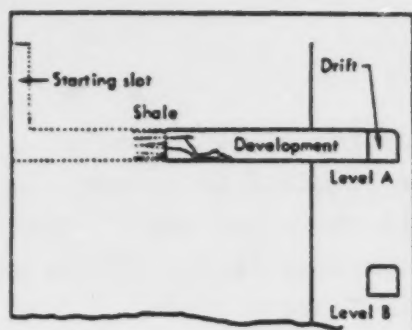
4.5.3.2 Input Requirements

This section reports inputs required for the operation and maintenance of a mine developing in-situ retorts. The various manpower, equipment, water, land, and energy requirements are largely based on data reported by Occidental in the 1977 Modifications to the Detailed Development Plan (MDDP) for Oil Shale Tract C-b. Estimates of capital requirements and annualized operating costs are likewise based on data reported by Occidental in the MDDP and its supplement.

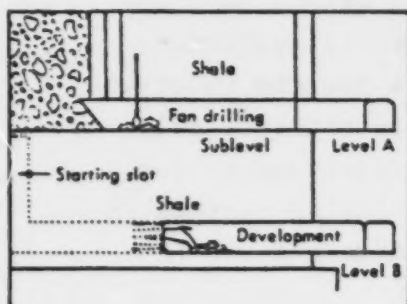
The inputs described in this section are representative of an in-situ facility producing 57,000 barrels of shale oil per day (as planned by Occidental). While Occidental's plan was specifically contrived for development on tract C-b, input requirements for facilities at other sites are not likely to be significantly different.

¹Rothman, A.J. "Research and Development on Rubble In-Situ Extraction of Oil Shale (RISE) At Lawrence Livermore Laboratory", Colorado School of Mines Quarterly, 70(3) 159-78 (1975).

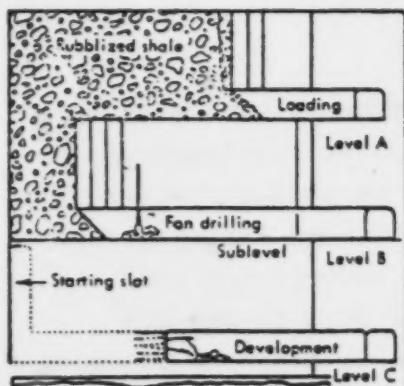
²Schora, F.C., P.B. Tarman and H.L. Feldkirchner, "In-Situ Oil Shale Processing", Hydrocarbon Processing, March 1977, p. 12.



1. DEVELOPMENT BEGINS AT TOP OF RETORT. HORIZONTAL DRIFTS ARE DRIVEN THE WIDTH OF THE BLOCK. A VERTICAL STARTING BLOCK IS DRIVEN TO PROVIDE A FREE BLASTING SURFACE FOR SUBSEQUENT DRILLING AND BLASTING.



2. SHALE IS LOADED AFTER EACH BLASTING OPERATION APPROXIMATELY 20% OF THE BROKEN SHALE IS EXTRACTED. THE REMAINDER FORMS THE RUBBLIZED RETORT.



3. DEVELOPMENT PROCEEDS SIMULTANEOUSLY ON MULTIPLE SUBLEVELS.

Figure 4-13. Modified Sublevel Caving Method Proposed For the Use in Rise Process.

Reference: Lewis, Arthur E., et. al. Rubble In-Situ Extraction (Rise): A Proposed Program For Recovery of Oil From Oil Shale. Lawrence Livermore Laboratory. March 5, 1975. p. 4.

4.5.3.2a Manpower

For Occidental's proposed complex producing 57,000 barrels of shale oil per day, mining operations are required to remove approximately 41,000 tons of low-quality oil shale per day.¹ Manpower requirements for a mining operation removing 41,000 TPD have been reported by Occidental and are shown in Table 4-39.²

The manpower requirements in Table 4-39 relate only the personnel requirements for full-scale commercial operations. Occidental has not reported skill breakdowns for the construction personnel required to establish the site prior to full-scale operations. However, total manpower requirements for developing the entire oil shale complex (including surface processing) have been reported by Occidental and are shown in Figure 4-14.³

4.5.3.2b Materials and Equipment

Detailed materials and equipment requirements have not yet been prepared by Occidental. However, equipment requirements for operating an in-situ mining development are generally similar to those for an underground mine. The Federal Energy Administration has estimated equipment requirements for an underground mine excavating 140,000 TPD oil shale. While the data in the FEA report are now somewhat outdated, an in-situ development removing

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor. February 1977. p. III-35.

²Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor. July 21, 1977.

³Ashland Oil, Inc. and Occidental Oil Shale, Inc., *op.cit.*, Figure I-6.

TABLE 4-39. MANPOWER REQUIREMENTS FOR IN-SITU MINING OPERATIONS^a

Skill	Number of Personnel
Production Staff	
Mine Superintendent	1
Assistant Mine Superintendent	1
General Mine Foreman	1
Shift Foreman	16
Chief Clerk	1
Mine Clerk	2
Mine Warehouseman	1
Warehouse Clerk	8
Conveyor Foreman (Surface)	4
Conveyor Foreman (Underground)	4
Technical Staff	
Chief Mine Engineer	1
Mine Engineer	3
Rock Mechanics Engineer	1
Assistant Engineer	8
Ventilation and Safety Engineer	1
Assistant Ventilation and Safety Engineer	4
Chief Surveyor	1
Mine Surveyor	8
Surveyor Helper	8
Chief Geologist	1
Geologist	2
Draftsman, Mine	2
Draftsman, Geology	1
Engineering Clerk	2
Maintenance Staff	
Maintenance Superintendent	1
Mechanic Foreman	8
Electrical Foreman	4
Maintenance Clerk	4
Direct Mine Labor	
Driller	132
Driller Helper	132
LHD Operator	24
Powderman	32
Powderman Helper	32
Powderman (Cap)	32
Powderman (Cap) Helper	32
Hoistman	8

(Continued)

TABLE 4-39. MANPOWER REQUIREMENTS FOR IN-SITU MINING OPERATIONS
(Continued)

Skill	Number of Personnel
Direct Mine Labor (Cont'd)	
Skip Tender	4
Crusher/Feeder Operator	20
Conveyor Operator (Surface)	8
Conveyor Operator (Underground)	8
Dozer Operator (Surface)	12
Utility Mine Labor	
Rockbolter/Scaler Operator	28
Rockbolter/Scaler Helper	28
Full Truck Driver	4
Full Truck Helper	4
Lube Truck Driver	4
Utility Truck Driver	48
Dozer Operator (Barricade)	4
Motor Grader Operator	8
Mine Labor	100
Conveyor Patrol (Surface)	24
Conveyor Patrol (Underground)	40
Toplander	8
Cage Tender	4
Janitor (Dry)	4
Maintenance Labor	
Hoister Oiler	8
Drill Doctor	16
Mine Mechanic	32
Mechanics Helper	32
Mine Electrician	32
Electrician Helper	32
Lampman (Dry)	4
TOTAL	1039

^aProduction capacity of in-situ complex of 57,000 BPD; excavation requirement of 41,000 TPD.

Reference: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plans for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor. July 21, 1977.

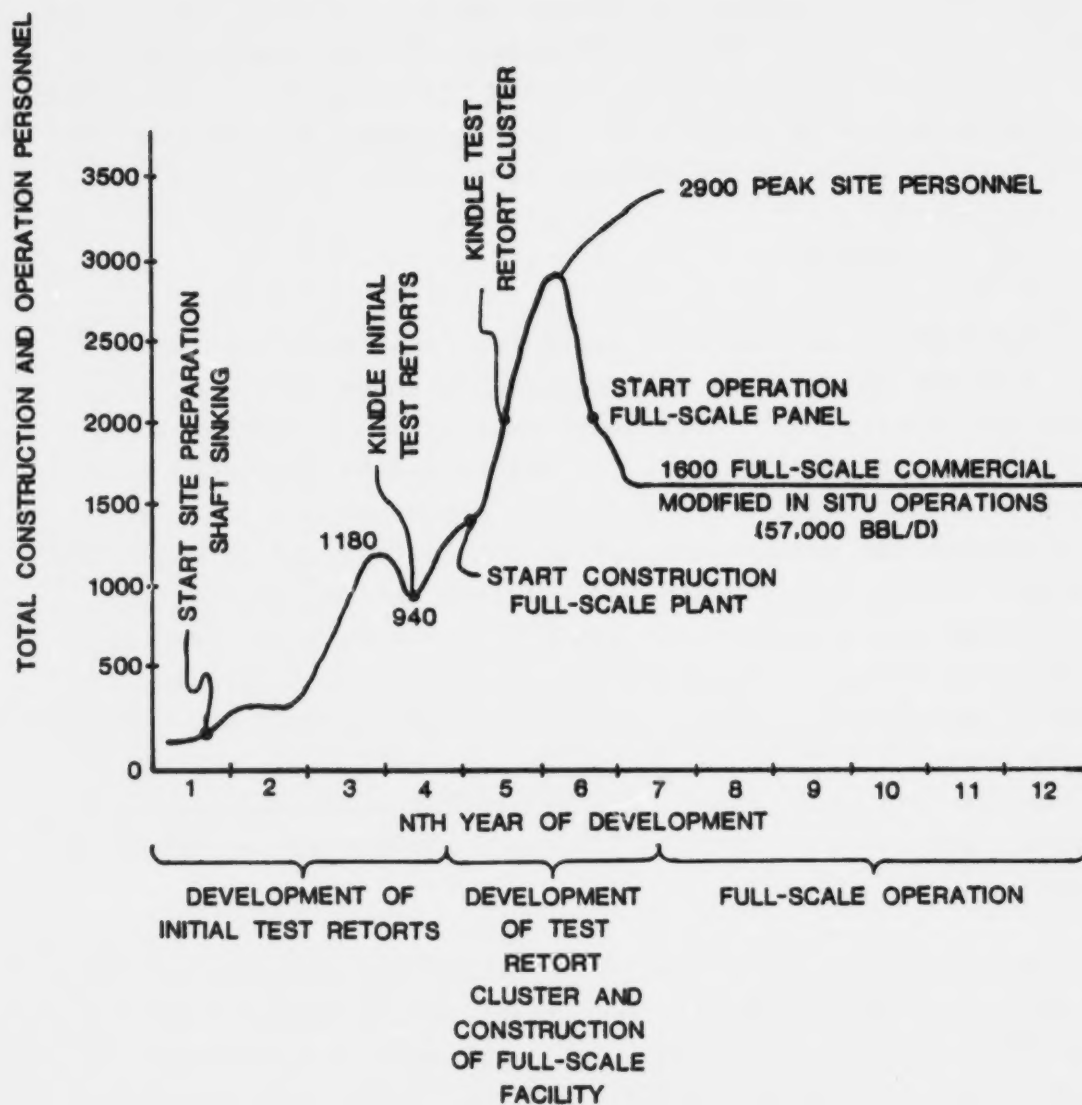


Figure 4-14. Manpower Projections.

Reference: Occidental Oil Shale, Inc. and Ashland Oil Inc.
Modified Detailed Development Plans for Oil Shale
Tract C-B. Prepared for Area Oil Shale Supervisor.
 February, 1977.

41,000 TPD may be assumed to require about a third of the equipment required for the 140,000 TPD mine. The equipment required for the in-situ development are scaled from data in the FEA report and are presented in Table 4-40. The equipment list is not complete and may be based on outdated information.¹

4.5.3.2c Economics

Preliminary capital cost estimates for a mine associated with a 57,000 bbl/d shale oil complex are shown in Table 4-41. These preliminary costs have been reported by Occidental in the MDDP for oil shale tract C-b, and should not be construed as definitive cost estimates. The estimates are based only on preliminary engineering design and project scheduling, and do not include interest during construction and deferred capital expenditures. The capital cost estimates reported in Table 4-41 include only those costs directly related to the mine, and exclude costs for general facilities, indirect costs, and working capital which were shared by the entire in-situ complex. Miscellaneous capital requirements (i.e., costs for general facilities, indirects, and working capital) for the entire in-situ complex are discussed in Section 4.6.2.2.²

Operating costs estimates for the OXY process were not reported in the MDDP or in the Supplement to the MDDP. However, data reported in the MDDP (and its supplement) can be used to contrive preliminary cost estimates. The labor costs are estimated from the labor requirements reported by Occidental in the

¹Federal Energy Administration, Interagency Task Force on Oil Shale, Project Independence Blueprint, Final Task Force Report, Potential Future Role of Oil Shale Prospects and Constraints. November, 1974. p. a-168.

²Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plans for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. February 1977. p. I-11.

TABLE 4-40. ESTIMATED EQUIPMENT LIST FOR MINING OF 41,000 TPD
FROM IN-SITU OIL SHALE COMPLEX

Equipment	Description	Number Required	Capacity	HP
Heading jumbo drills	Hydraulic electric with two drills	4	---	150
Bench jumbo drills	Hydraulic electric with two drills	2	---	150
Powder trucks	Diesel drive with pneumatic delivery system	4	3 tons	100
Scaling and roof bolting rigs	Diesel drive with aerial lift	4	---	500
Front end loaders	Diesel drive	4	20 tons	700
Haulage trucks	Diesel drive	12	75 tons	700
Motor Patrols	Diesel drive	2	---	150
Bulldozers	Diesel drive	4	---	700
Road graders	Diesel drive	2	---	225
Water trucks	Diesel drive	4	---	---

NOTE: Actual equipment list for mining of in-situ facility may differ substantially from the
above list.

Reference: Federal Energy Administration, Interagency Task Force on Oil Shale, Project Independence
Blueprint, Final Task Force Report, Potential Future Role of Oil Shale Prospects and
Constraints, November 1974, p. A-168.

TABLE 4-41. MINING CAPITAL COST ESTIMATES FOR
AN IN-SITU OIL SHALE COMPLEX^{a, b, c}

Shafts, Hoist, Appurtenances	\$ 38,053,000
Mobilization	9,537,000
Equipment and Spares	21,450,000
Conveyors and Materials Handling	19,003,000
Labor	18,360,000
Other Materials	29,328,000
Taxes	965,000
	<u>\$136,696,000^d</u>

^aCosts are in 1977 dollars.

^bCosts are those reported by Occidental.

^cShale oil production capacity of 57,000 BPD, excavation requirement of 41,000 TPD.

^dGeneral facilities costs, indirect costs, and working capital are reported for entire facility in Section 4.6.2.2.

Reference: Ashland Oil, Inc. and Occidental Oil Shale, Inc.
Modifications to Detailed Development Plans for Oil
Shale Tract C-b. Prepared for Area Oil Shale Super-
visor. February 1977. p. I-11.

Supplement to the MDDP. Utilities' costs are estimated from the power and fuel requirements reported in the MDDP and its supplement. All other costs are estimated as percentages of the capital or labor costs. These estimates are shown in Table 4-42, and are based on preliminary, incomplete data.

4.5.3.2d Water

Most of the water required for an underground mining operation is needed for dust control. Occidental has estimated water requirements to be 450 gpm (730 acre-ft/year) for mining in a 57,000 bbl/d shale oil complex. Essentially the entire water requirement could be met with readily-available untreated mine-water. Water requirements for revegetation of mined-out shale are discussed in Section 4.7, Reclamation.¹

Occidental has also estimated the water required during construction of the in-situ facility. Consumptive uses during construction include concrete manufacture, dust control, and fill compaction. Quantities for these uses amount to 500-700 gpm (800-1100 acre-ft/year). The entire requirement could be met by water from dewatering operations.²

4.5.3.2e Land

Occidental has made estimates of the land areas disturbed by an in-situ development. In the development of a 57,000 bbl/d facility, approximately 40 acres are required for mine shafts

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plans for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. February 1977. p. III-29.

²*Ibid.*, p. III-42 to 44.

TABLE 4-42. ANNUALIZED OPERATING COSTS FOR MINING
AT AN IN-SITU OIL SHALE COMPLEX^{a, b}

Direct Costs		
Mine Labor	\$12,000,000 ^c	
Maintenance Labor	2,300,000 ^c	
Maintenance Staff	350,000 ^d	
Technical and Production Staffs	1,600,000 ^d	
Total Labor and Supervision	16,000,000	
Operating Supplies	1,400,000 ^e	
Maintenance Materials	2,300,000 ^f	
Utilities		
Electricity	9,200,000 ^g	
Water ^h	-	
Diesel Fuel	1,300,000 ⁱ	
Fixed Costs		
Depreciation	14,000,000 ^j	
Taxes and Insurance	4,100,000 ^k	
Plant Overhead	8,000,000 ^l	
TOTAL	\$56,000,000	\$2.70/bbl

^aCosts are in 1977 dollars and include only those costs directly attributed to the mining operation.

^bShale oil production capacity of 57,000 BPD; excavation requirement of 41,000 TPD.

^cCalculated @ \$15,000/man/year.

^dCalculated @ \$20,000/man/year.

^eCalculated @ 1% of the fixed capital costs.

^fCalculated @ 100% of maintenance labor.

^gCalculated @ \$0.04/kwh.

^hEssentially all water requirements are met by use of minewater.

ⁱCalculated @ \$0.50/gal.

^jCalculated @ 10% of fixed capital.

^kCalculated @ 3% of fixed capital.

^lCalculated @ 50% of total labor costs.

NOTE: Rates for calculating fixed costs, plant overhead, and costs for operating supplies and maintenance materials are largely based on Peters, M.S. and K.D. Timmerhaus. Plant Design and Economics for Chemical Engineers, 2nd. Ed. (New York: McGraw-Hill Book Co., 1968). pp. 132-141.

References: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plans for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. February 1977. p. I-11.

Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plans for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. July 21, 1977.

and related support structures. Road construction for the entire complex requires about 60 acres. Land requirements for holding ponds for excess minewater have not been specified. Total land requirements for fixed surface facilities are on the order of 100 acres.¹

If mined-out shale is not retorted on the surface, about 100 additional acres will be required each year for the disposal of mined-out shale.²

4.5.3.2f Ancillary Energy

Ancillary energy requirements for an underground mine have been reported by Occidental, and are tabulated in Table 4-43.^{3, 4} The energy recovery ratio of mining for in-situ processing is included in the value reported in Section 4.6.2.2 for the overall modified in-situ processing development.

4.5.3.3 Outputs

This section reports the various outputs associated with the operation of a mine developing in-situ retorts. Discussions of air emissions, water effluents, solid wastes, and noise pollution are largely based on information reported by Occidental in the MDDP and its supplement. Although Occidental's data are

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plans for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor, February 1977, p. I-13.

²*Ibid.*

³*Ibid.*, p. III-39.

⁴Ashland Oil, Inc. and Occidental Oil Shale, Inc., Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor, July 1977.

TABLE 4-43. ANCILLARY ENERGY REQUIREMENTS FOR MINING IN AN IN-SITU OIL SHALE FACILITY^a

Category	Power or Fuel Requirements	Energy Usage
Electricity		
Hoisting	20,950 hp	1.15 x 10 ⁸ kwh/year ^b
Drilling	7,000 hp	3.6 x 10 ⁷ kwh/year ^c
Ventilation	3,600 hp	2.4 x 10 ⁷ kwh/year ^d
Dewatering	4,400 hp	2.9 x 10 ⁷ kwh/year ^d
Breaking and Conveying	2,500 hp	1.3 x 10 ⁷ kwh/year ^c
General Services	-	1 x 10 ⁷ kwh/year
TOTAL		2.3 x 10 ⁸ kwh/year ^e
Diesel Fuel	7000 gal/d	3.4 x 10 ¹¹ Btu/year ^f

^a Shale oil production capacity of 57,000 BPD; excavation requirement of 41,000 TPD.

^b Assumes mine operates 350 days/year, 3 shifts/day, 7 hours of hoisting/shift.

^c Assumes mine operates 350 days/year, 3 shifts/day, 6.5 hours (eff.)/shift.

^d Assumes ventilation and dewatering requirements occur 365 days/year.

^e Figure represents electricity directly used in mining. Gross power plant energy requirements can be estimated by using power plant heat rate of 9750 Btu/kwh (power generation efficiency of 35%).

^f Assumes mine operates 350 days/year; heating value for diesel fuel of 140,000 Btu/gal.

References: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. February 1977. p. III-39.

Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. July 1977.

specific to oil shale tract C-b, outputs for in-situ development at other locations are probably very similar. However, the environmental impacts from these outputs do vary from site to site.

4.5.3.3a Air Emissions

Air emissions from mining operations originate from the production shaft mine vent, the shale conveyor, and the shale disposal area. Mine vent emissions are shown in Table 4-44 and are discussed below. Emissions resulting from the transportation and disposal of mined-out shale are shown in Table 4-45. Air emissions from mining operations are those reported by Occidental for a 57,000 bbl/d facility in the supplement to the MDDP.

Emissions arising from underground mining operations exit the mine vent and are shown in Table 4-44. Conventional mining operations (i.e., mining, blasting, hauling, and crushing) are the largest sources of particulates. Blasting operations required to rubble the shale formation are the largest sources of sulfur dioxide, carbon monoxide, and nitrogen oxides. Diesel equipment is the largest source of hydrocarbon emissions. The emissions data in Table 4-44 assume a baghouse 99% efficient in controlling particulate emissions originating from the mine vent. Diesel equipment is assumed to be equipped with catalytic converters 90% efficient in controlling carbon monoxide and hydrocarbon emissions.¹ Emissions from the transportation and disposal of mined-out shale have also been estimated by Occidental, and are shown in Table 4-45. Estimates of both uncontrolled and controlled particulates emissions are reported, with possible control technologies reported at the bottom of the table.

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor, July 1977.

TABLE 4-44. MINE VENT EMISSIONS FROM MINING IN AN IN-SITU
OIL SHALE FACILITY PRODUCING 57,000 BPD

Pollutant	Averaging Time	Mining, Blasting Hauling, Crushing	Emission Rate (lb/hr)			Total ^c
			Rubbling ^b	Diesel Equipment		
Particulates	24-hr	10.3	1.4	3.8		15.5
	Annual	10.3	0.3	3.8		14.4
SO ₂	3-hr	1	43.3	0.8		45
	24-hr	0.3	5.4	0.8		7
	Annual	0.3	1.1	0.8		2
CO	1-hr	274	18,800	65.6		19,140
	8-hr	34.3	2,350	65.6		2,450
	Annual	34.3	157	65.6		257
TMC	3-hr	0.7	47	10.8		58.5
	Annual	0.3	1.2	10.8		12.3
NO _x	Annual	34.3	157	108.2		299.5
CO ₂	Annual	--	--	6200		6200 ^d

^c Emission rates from the mine vent depend on the averaging time for the products from the rubbing blast.

^b Rubbling is assumed to occur not more than once per 24-hour period.

^c Stack characteristics: height, 88m; diameter, 3.3m; volumetric flow, 636,354 scfm; exit temperature, 73° above ambient.

^d Based on complete combustion of carbon compounds in diesel fuel to carbon dioxide.

Source: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor, July 1977.

TABLE 4-45. PARTICULATE EMISSIONS FROM TRANSPORTATION
AND DISPOSAL OF MINED-OUT SHALE

Source	Emissions Lb/Hr	
	Without Control	With Control
Mine Shaft--Conveyor Transfer Point	170.8	1.7 ^a
Shale Conveyor	51.3	7.7 ^b
Shale Disposal	145	29 ^c

^a A wet scrubber reduces emissions by 99%.

^b Wet suppression (with chemical additives, if necessary) controls emissions by 85%.

^c Wet suppression controls emissions by 80%

Reference: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Modifications to Detailed Development Plan for Oil Shale Tract C-b, prepared for Area Oil Shale Supervisor, July 1977.

4.5.3.3b Water Effluents

Potential water effluents from mining operations include: excess minewater, runoff from raw shale piles, and sanitary wastewaters. Volumes of these potential water effluents have not been estimated. Quantities and qualities of excess mine-water and runoffs are largely dependent on the site of the in-situ development. Characteristics and disposal of these water effluents have been discussed in Section 4.5.1.3.

4.5.3.3c Solid Wastes

Mining operations for Occidental's 57,000 bbl/d facility excavate about 41,000 tons of raw oil shale per day. Nearly all of the mined-out shale can be disposed of on the mine property. The area required for shale disposal is estimated at 100 acres per year. If the mined-out shale is surface retorted, somewhat larger disposal areas are required. Inorganic salts, toxic metals, and some toxic organics are contained in both raw and retorted shale. Some potential exists for back-filling the underground complex. However, disposal of shale by back-filling has not been demonstrated and will not consume all of the shale.¹

Water treatment sludges result from upgrading minewater for retorting/processing, and are discussed in Section 4.6.2.3.

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. February 1977. p. III-43.

4.5.3.3d Noise Pollution

Noise at the underground mine originates from normal mining operations and from the large blasts required to rubble retorts. Sound levels within the mine during mining operations are similar to those encountered in underground coal mines. Typical ranges of sound levels at worker positions are shown in Table 4-46.

Noise levels that exist during blasting have not been measured or estimated. Hazards to workers can be minimized by evacuating personnel from those areas most affected by the blasts. The rubbing blast is not usually heard at distances farther away than 500 to 600 yards from the blast.¹

4.5.3.3e Occupational Health and Safety

Health and safety hazards associated with the mining of an in-situ complex have not been extensively examined. Safety hazards for an in-situ mining operation are probably similar to those for standard underground mines. Using data estimated for an underground shale mine, approximately 21 injuries and 0.5 fatalities will occur annually in a mine excavating 41,000 tons of shale per day. (That shale excavation rate corresponds to an in-situ complex producing 57,000 bbl/d.)²

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. February 1977. p. V-4.

²Hittman Associates, Inc. Environmental Impacts, Efficiency and Cost of Energy Supplied by Emerging Technologies. Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Prepared for Council on Environmental Quality. National Science Foundation and Environmental Protection Agency. Contract EQC 308. Columbia, MD. May 1974.

TABLE 4-46. NOISE LEVELS ENCOUNTERED BY MINE WORKERS^a

Noise Source	Sound Level, dbA
Roofbolter/Scaler	107 - 118 ^b 92 - 101 ^c
Drill	80 - 104
Air Pump/Fan	90 - 105
Conveyor	90 - 105 ^d 75 - 85 ^e
Crusher/Feeder	90 - 105
LHD	90 - 108
Sump	93 - 98
Hoist	85 - 95

^aData assumes that underground shale mines and underground coal mines have similar noise sources and characteristics.

^bPneumatic roofbolter.

^cRotary roofbolter.

^dFlighted conveyor.

^eBelted conveyor.

Source: U.S. Department of the Interior. Noise Control Proceedings: Bureau of Mines Technology Transfer Seminar, Pittsburgh, PA. January 22, 1975, pp. 6, 95.

Health hazards for an in-situ mining operation are chiefly associated with worker exposure to shale dust, raw shale, and toxic gases. These hazards have been discussed in Section 4.5.1.3. Another potential hazard is worker exposure to off gas from operating retorts. This hazard can be avoided by conveying the off gas through gas drifts completely isolated from all mine workings (as planned by Occidental).

4.5.3.3f Odors

Odors at the mine are chiefly associated with nitrogen oxides, sulfur dioxide, and hydrogen sulfide emitted during mining operations. These odors are likely to be confined to the mine site.

The inputs and outputs associated with a modified in-situ mining development are summarized in Table 4-47.

4.5.4 Social Controls

After a feasible potential oil shale deposit has been located, the land and the approval of the regulating bodies must be obtained. Both the acquisition of the lands and the required permits to mine will be discussed in the following sections.

In addition to the regulation of the procedure to obtain the lands for mining, some jurisdictions will also regulate mine safety. The following sections describe both.

TABLE 4-47. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED
WITH A MINE EXCAVATING 41,000 TPD OF OIL
SHALE FOR A MODIFIED IN-SITU DEVELOPMENT

<u>Inputs</u>		
Manpower		
• operating	1039 men	
Materials and Equipment		
• jumbo drills	6	
• powder trucks	4	
• scaling and roof bolting rigs	4	
• front-end loaders	4	
• haulage trucks	12	
• bulldozers	4	
Economics ^a		
• capital	\$140,000,000	
• annualized operating	\$56,000,000	
Water	450 gpm	
Land		
• mine shafts, support structures, roads	100 acres	
• mined-out shale	100 acres/yr	
Ancillary Energy		
• electricity	2.3×10^8 kwh/yr	
• diesel fuel	7000 gal/d	
<u>Outputs</u>		
Air Emissions		
• particulates	382 lb/hr	
• hydrocarbons	12 lb/hr	
• NO _x	300 lb/hr	
• CO	260 lb/hr	
• SO ₂	2 lb/hr	
• CO ₂	6200 lb/hr	
Water Effluents	Extremely site dependent	
Solid Wastes		
• raw shale	41,000 TPD	
Noise Pollution		
• at mine boundary	Negligible	
Occupational Health and Safety		
• deaths	0.5/yr	
• injuries	21/yr	
Odors	Confined to mine site	

^a1977 dollars

4.5.4.1 Obtaining Lands

The land may be owned by the federal government, individual Indian or Indian tribes, or private corporations or individuals. Leasing procedures vary according to who owns the land. The following sections describe procedures for obtaining lands for oil shale development in these categories.

4.5.4.1a Federal Lands

At the present time, no federal oil shale leases are being granted. The most recent leasing, in 1973, was the prototype lease sale which will be described below.

In 1968, the Department of the Interior undertook a review of federally owned oil shale resources, including the formulation of environmental impact analyses, and the development of a new prototype leasing program. The result of this review, the Prototype Oil Shale Leasing Program, was announced by Interior in 1971 and approved for implementation in 1973.

Under the prototype lease program, six tracts of approximately 5,000 acres each were to be leased under a bonus bid system. Sale of the six tracts began in January 1974, and was completed by mid-1974. Only four of the six were leased, two each in Colorado and Utah: no bids were received for the two Wyoming tracts.

According to Interior, the Prototype Program is intended to:

- 1) Provide a new energy source by stimulating private commercial technological development;
- 2) Insure the environmental integrity of affected areas;
- 3) Permit an equitable return to the parties that develop the resources; and
- 4) Develop management and supervisory expertise in oil shale leasing for the future.¹

Some federal lands are excluded from oil shale development under the Prototype Program, including: 1) all national forests; 2) all Naval Oil Shale Reserves; 3) designated fish and game experimental or management areas; 4) designated historical landmarks, 5) oil shale experimental sites, and 6) lands reserved for other minerals.²

The Department of Interior's overall responsibility for federally owned oil shale lands and resources is comparable to that for coal lands. The Secretary has discretionary authority to lease and manage these lands and may withdraw certain lands from leasing or modify previous withdrawals to permit leasing mineral rights on public lands. Only the Department of the Interior may initiate the leasing process for oil shale, although

¹U.S. Congress, House. Science and Astronautics Committee. Energy from Oil Shale. 1973. p. 54.

²U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program. 6 vols. Washington, D.C. 1973.

the Department may invite private parties to nominate tracts. But regardless of how nominated, USGS evaluates the resource potential.

Sealed bids together with 20 percent of the bonus bid amount must be submitted before the scheduled sale date. Usually a lease will be awarded to the qualified party offering the highest bonus bid; however, the Secretary does have the discretionary authority to reject any bid.

The purchaser pays the remaining 80 percent of his bonus bid in four equal annual installments.¹ However, certain expenditures such as capital costs for mining and processing equipment can be credited against the last two payments.

Bonus bids were quite high on the four tracts sold in the Program. The first tract bid was \$210 million, a per-acre bonus of almost \$42,000. Winning bids on the other three tracts were lower.

The minimum rental fee, fixed by statute, is 50 cents per acre per year. Royalty rates were left to the discretion of the Secretary. In the Prototype Program, royalty rates were fixed at 12 cents per ton for oil shale containing 30 gallons of oil per ton, and at varying rates for other grades of shale. Royalty rates may be adjusted as crude oil prices change, and additional payments may be required for minerals other than oil recovered during oil shale operations. For the Prototype Program, the minimum

¹U.S. Congress, House. Science and Astronautics Committee. Energy from Oil Shale. 1973. p. 54.

royalty is \$16 million for each 1.5 billion barrels of recoverable oil, over the twenty year lease period. A reduction of royalty of one-half the difference between minimum and actual royalty will be given in the eighth year of the lease. And, at his discretion, the Secretary may charge "unanticipated environmental costs" or some other expenditures against royalty payments.

The Secretary is authorized to issue the lease for an "indeterminate" period. In the Prototype Program the term is fixed at twenty years or for "as long as the lease is producing commercial quantities of oil." At the discretion of the Secretary, the terms of the lease may also be readjusted at the end of the initial twenty years.

Holdings are limited to approximately 5,120 acres by the Prototype Program. Not more than one lease may be granted per person, association, or corporation; however, indirect ownership of more than one lease is permitted as long as the 5,120 acre total is not violated.

An important factor is the environmental controls which are stipulated to by the energy developer. The stipulations¹ are included by reference in the lease itself making the developer bound by contract law rather than criminal or civil sanctions.¹ These stipulations are quite comprehensive and include the following categories: general, access and service plans, fire prevention and control, fish and wildlife, health and safety, historic and scientific values, oil and hazardous materials, air pollution,

¹Phillips, David F. "Legal Mechanisms for Access to Coal and Oil Shale." Stanford Research Institute. 1976. pp. 7-37 through 7-38.

water pollution, noise pollution, rehabilitation, scenic values, vegetation, and waste disposal.¹

4.5.4.1b Indian Lands

Procedures for acquiring Indian lands for oil shale development are similar to those for coal development on federal lands; both the federal government and the appropriate Indian authorities have veto power over leasing decisions.

Although Indian lands are not an integral part of the public domain, Indians do not have complete legal title. There are two principal categories of Indian lands: allotted, where title has been partially transferred to individual Indian landowners, and tribal, where the lands are collectively owned. The Bureau of Indian Affairs (BIA) acts as a trustee, both for individual Indians and tribes, its stated goal being to protect Indian interests by providing assistance and service in granting permits and making leases.

The general provisions and procedures for leasing Indian lands for oil shale are listed as follows:

- 1) Interest initiated by tribes or private individuals.
- 2) Nominations approved by Indians and BIA.
- 3) EIS process if applicable.
- 4) Lease sale held.

4.5.4.1c State Lands

As noted earlier, most states have reserved their minerals, making a lease with royalty to the state the only method available

¹U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program. 6 vols. Washington, D.C. 1973.

for mineral (including oil shale) development. As noted in Section 4.4.4 Colorado has no state lands in the oil shale area; hence, this section will discuss the leasing of lands from the states of Utah and Wyoming only.

The state of Utah has adopted an attitude favoring oil shale development on its state lands. Statutes provide that there shall be no royalty (which could be up to 12½ percent) on the first 200,000 barrels of commercial production from oil shale from state lands.¹ Another provision allows the State Land Board to credit a meritorious oil shale plan against future rentals to an amount designed not to reduce rentals below 50¢ per acre per year.²

Although many states entered the Union with grants of one or two sections of land per township to the state for the support of common schools, Utah, along with some other states, entered the Union with a grant of four sections per township.³ Because of potential claimant conflicts on the granted lands, title would not vest in the state until a survey was complete and there were no third party claims. When a prior transfer of the title of the school lands to a third party had occurred, the states were allowed to make "indemnity selections" or exchanges of those sections for others within federal lands. The enabling legislation for the states also specified that the selected land not be "mineral" in character. This was amended in 1958 and 1966 to allow the states

¹Utah Code Annotated § 65-1-109 (Cum. Supp. 1975).

²Utah Code Annotated § 65-1-113 (Cum. Supp. 1975).

³The thought was that the arid nature of the land required more of it to provide an equal footing. Utah and the other arid states received sections 2, 16, 32, and 36. See Enabling Act of July 18, 1894, ch. 138, § 6, 28 Stat. 107, 109.

to select mineral lands in exchange for mineral lands which were owned by a third party.¹

Utah has aggressively pursued this exchange procedure and by 1975 had acquired an acreage subject to in-lieu selection of 200,000 acres and further had shown that 160,000 acres of that should be "mineral" in nature.² Between 1965 and 1971, Utah made application to have 157,255.90 acres of its mineral selection lands picked from federal lands in Uintah County, Utah - the location of the federal oil shale leases. The application by Utah resulted in repeated delays by Interior and consequently Utah proceeded to court for a declaratory judgment.³ If Utah is upheld in its request for title, its leasing policy toward state lands for oil shale development would be a major factor in encouraging oil shale development.

Although Wyoming has oil shale within its boundaries and the state does own some school sections (640 acre tracts), the feasibility of developing such small tracts is minimal. There was hope that the federal leases on tracts W-a and W-b in Wyoming (for in-situ recovery) would also lease the contiguous state lands. When the federal leases failed to draw any bidders, Wyoming decided to write a new set of regulations specifically for oil shale leasing.⁴

Presently existing statutory procedures for leasing state lands for oil shale development in Utah and Wyoming are summarized in Tables 4-48 and 4-49.

¹72 Stat. 928 and 80 Stat. 220, respectively.

²Eliason, Max D. "Land Exchanges and State In-Lieu Selections as They Affect Mineral Resource Development." In: Rocky Mountain Mineral Law Foundation, p. 640.

³Utah v. Hathaway. Civil No. C-74-64, (D. Ut. Mar. 4, 1974).

⁴Phillips, David F. "Legal Mechanisms for Access to Coal and Oil Shale." Stanford Research Institute. 1976. pp. 7-37 through 7-38.

TABLE 4-48. WYOMING OIL SHALE LEASE

Item	Statutes	Summary
Agency	§36-74	Board of land commissioners, Commissioner of public lands
Requirements		None
Fees	§36-42	Fee for filing a lease application is \$15
Rental		None
Royalty		None
Duration	§36-74	Not more than 10 years, with preferential right to renew for 10 year periods
Bond		None
Other Information	§36-74	The agency above has authority to set rates and terms in its rules and regulations within confines of specific statutes noted above

Source: Wyoming Statutes of 1857.

TABLE 4-49. UTAH OIL SHALE LEASE

Item	Statutes	Summary
Agency	§65-1-18	State Land Board
Requirements		None
Fees	§65-1-24	15¢ per acre
Rental	§65-1-18	Not less than 50¢ per acre per year, nor more than \$1.00 per acre per year
Royalty	§65-1-18	Not more than 12½% of gross
	§65-1-109	No royalty on first 200,000 barrels of first commercial production in Utah
Duration	§65-1-18	Not less than ten years and for so long as producing
Bond	§65-1-90	Required only to reinstate lease after failure to pay for damage to surface amount discretionary
Other Information	§65-1-45	Newly acquired lands and lands with an expiring lease must be let through competitive bids, all others leased to first applicant
	§40-8-13	If this is a mining operation (surface) the developer must submit a plan of reclamation and before operations start also execute a bond for surface damage. The Board of Oil, Gas, and Mining controls this aspect. The board determines amount of bond
	§40-8-14	

Source: Utah Code Annotated (1953).

4.5.4.1.d Private Lands

Sizeable blocks of land are needed to make the oil shale conversion process economically feasible. At present in Utah there is one block of private land known as the Watson Property which is economically feasible and which has been estimated to contain 500-700 million barrels of shale oil.

The statutes which control oil shale development at the mineral acquisition stage on private land are state laws concerning contracts and case law that has developed under mineral lease clauses. Of course, with the promise that individuals are free to contract as they wish, the only input from state law would be that arising if the contracts-leases were taken to court for enforcement.

To acquire a large block of single-owner oil shale land, a private owner may exchange land with the federal government.¹ The Bureau of Land Management is authorized to make such exchanges of federal land for private land if and only if the "public interests will be benefited thereby." Additional requirements for the exchange are that the value of federal lands given up not exceed the value of the exchanged land and that the exchanged lands not be more than fifty miles from the base lands if located in another state. If they are within the same state they may be any distance apart.

In 1974 because of the importance of land exchanges and oil shale development the Department of Interior issued a "Department Policy for Exchange of Oil Shale Lands" which stated:²

¹43 U.S.C. 315g (c) (1970). This process is currently being undertaken by Superior Oil Company.

²Eliason, Max D. "Land Exchanges and State In-Lieu Selections as They Affect Mineral Resource Development." In: Rocky Mountain Mineral Law Foundation, Vol. 21, p. 640.

...The Department of Interior recognized that oil shale resources could contribute significantly to the domestic energy supply by 1980-1985... It is the policy of the Department to the Interior to facilitate efficient and environmentally safe development of both private and public oil shale lands and to encourage the development of new technology through a program of land exchanges designed to consolidate land ownerships, thereby eliminating intermingled ownership land patterns.

The procedures for exchanging privately owned oil shale lands for Federal oil shale lands is prescribed in the Code of Federal Regulations.¹ The application must include a description of both lands, a list of the reservations and exceptions to the titles of the lands involved, a description of water resources on both lands, a statement of the purpose of the exchange and the public interest factor, information on the value of the lands, and a petition to the Secretary of Interior to allow the exchange of withdrawn lands (if necessary).²

In order to determine whether the lands exchanged are of equal value, the U.S.G.S. is required to consider the whole of the oil shale development plan to weigh its feasibility. A document entitled Exchange of Oil Shale Lands - Appraisal Proceedings, was published in 1975 by the Colorado BLM Office and the Central Region U.S.G.S. Office and suggested the following factors be considered:³

- 1) The current market value of the offered lands must be equal to or exceed the current market value of the selected lands. This must include all resource values.

¹43 C.F.R. §§ 2200 et seq. (1974).

²43 C.F.R. §§ 2400 et seq. (1974).

³Eliason, Max D. "Land Exchanges and State In-Lieu Selections as They Affect Mineral Resource Development." In: Rocky Mountain Mineral Law Foundation, Vol. 21, p. 640.

- 2) The proposed use of the lands to be exchanged must not result in an unacceptable impact on the environment.
- 3) The exchange must be in the public interest.

As always in the West, the burden on the title of private lands by mining claims must be considered. The Department of the Interior seems willing to accept such lands, but procedures to identify the claimants and purchase their rights must be followed.¹

4.5.4.2 Health and Safety

Health and safety regulations for oil shale mining, whether underground or surface, are no different from the general safety regulations described in Chapter 2 of this report.

4.5.4.3 Mining Permits and Reclamation

Both federal and state regulations control mining and/or reclamation associated with oil shale development. Federal controls are those stemming from federal ownership of the land environmental stipulations of the Prototype Oil Shale Leasing Program. Both of these federal controls are described below. State laws also will be noted below along with a discussion of the application of state laws to federal land.

¹Eliason, Max D. "Land Exchanges and State In-Lieu Selections as They Affect Mineral Resource Development." Rocky Mountain Mineral Law Foundation, Vol. 21, p. 834.

4.5.4.3a Federal Controls

The regulations set out in the Code of Federal Regulations¹ are the same as those applicable to coal reclamation and are described in Chapter 2.

Those reclamation controls set out in the federal leases under the Prototype Oil Shale Leasing Program require generally that the lessee shall:²

backfill and/or reclaim excavated material and processed shale and compact it thoroughly; design slope faces of waste piles to insure slope stability; revegetate slope faces and other areas in accordance with the rehabilitation plan; and comply with numerous requirements for the restoration of disturbed land.

More specifically, Section 11 of the environmental regulations controls reclamation.

Three separate bonds must be executed if the oil shale developer is working on a federally owned and leased land. First a compliance bond of \$20,000 is required.³ Secondly a reclamation bond, set initially at \$2,000 per acre for spent shale disposal sites and \$500 per acre for other areas, is required.⁴ Last there is an additional compliance bond of not less than \$20,000 conditioned on compliance with 30 C.F.R. Part 231 (Mine Operation Regulations), 43 C.F.R. Part 23 (Reclamation), the environmental stipulations, the

¹43 C.F.R. Part 23.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials. Prepared for Area Oil Shale Supervisor for Tract C-b. February 1976. p. V-96.

³Phillips, David F. "Legal Mechanisms for Access to Coal and Oil Shale." Stanford Research Institute. 1976. p. 7-41.

⁴*Ibid.*, p. 7-42.

development plan, and anything else which may affect the environment.¹ The amount of the bond is negotiated in the terms of each lease.

4.5.4.3b State Controls

State reclamation controls discussed in Chapter 2 including mine permits would be applicable to oil shale reclamation on private and state lands. Note also that Wyoming has succeeded in having the state reclamation laws applicable to coal mining on federal land with the state.² Whether this will be true of oil shale development is not known at this time.

¹Phillips, David F. "Legal Mechanisms for Access to Coal and Oil Shale." Stanford Research Institute. 1976. p. 7-42.

²See Chapter 2 ERDS.

4.6 PROCESSING

As previously described in Section 4.5, two major options are available for oil shale development. These are:

- 1) mining of the shale deposit, followed by surface processing of the mined-out shale, and
- 2) underground or in-situ processing.

Sections 4.6.1 and 4.6.2 discuss surface and in-situ processing. Section 4.6.3 briefly discusses a scheme combining both processing technologies.

Oil shale processing comprises two distinct activities: retorting and upgrading. Retorting is the pyrolysis reaction in which kerogen is decomposed and stripped from shale to yield hydrocarbon gases, liquids, and a carbonaceous residue. "Pyrolysis" is the heating of organic material in an oxygen lean atmosphere that inhibits complete oxidation. Retorting temperatures generally exceed 900°F.

Upgrading improves the characteristics of retorting gaseous and liquid products. Liquid products can be upgraded for transportation to refineries or for consumer use. Gaseous products are usually upgraded for use as fuel by the processing facility. Major technology choices involve the selection of a retorting process, and the determination of the degree of upgrading to be performed on site. Shale oil upgrading is discussed in Section 4.6.1.1.

4.6.1 Surface Processing

4.6.1.1 Technologies

Figure 4-15 is a classification of in-situ and surface retorting technologies. Current surface retorting processes involve either solid-solid or solid-gas heat transfer. Processes which involve solid-solid heat transfer rely on heated solids such as ceramic balls, sand, or processed shale to supply the heat required for retorting. Such processes heat the particles in an external heater and then mix them with the raw shale in the retort. After retorting, the heat-carrying solids must be separated from the processed shale for recycle to the retort. Product gases and condensable vapors are taken overhead.

Surface processes which involve gas-solid heat transfer use either internal gas combustion or external heat generation. Processes using internal gas combustion inject air directly into the retort. The heat liberated from the resulting combustion of both carbon residue on the shale and recycled retort gas provides the heat required for retorting. Processes using external heat generation rely on external heaters to provide a high-temperature recycle gas which is then routed to the retort. The heat contained in the recycle gas raises the temperature of the shale to that required for retorting. Combustion of carbon residue on the processed shale does not occur in the retort.

The following sections describe six of the major surface retorting processes.

4.6.1.1a TOSCO II Oil Shale Process

The TOSCO II process is an improved version of the ASPECO process, which The Oil Shale Corporation (TOSCO) purchased in 1952. Initial development work was conducted under TOSCO sponsorship by the Denver Research Institute in a 24-ton per day (TPD) pilot plant during 1955-1966. In 1964, a joint venture of

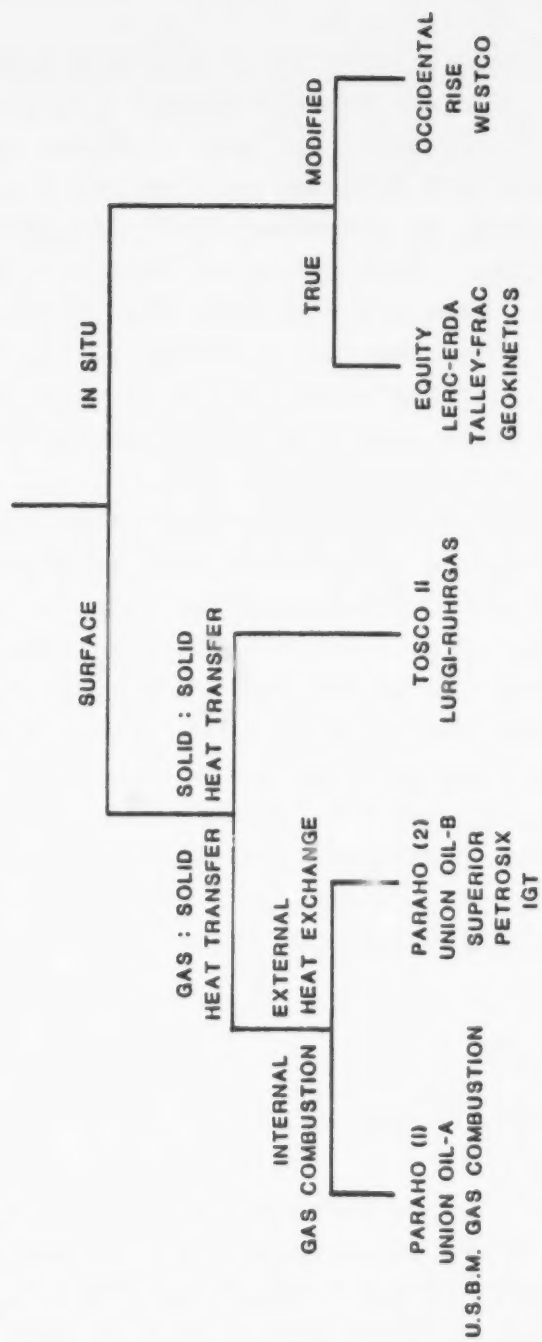


Figure 4-15. Classification of Retorting Methods.

Standard Oil Company of Ohio, Cleveland Cliffs Iron Company, and TOSCO, known as the Colony Development Company, was formed to commercialize the process. The Colony Development Operation¹ conducted field tests until 1972 in a 1,000 TPD semiworks plant. A full-scale 66,000 TPD commercial plant producing 47,000 BPD of low sulfur fuel oil and 4300 BPD of LPG has been designed. The plant would be located on the Dow West property of the Middle Fork of Parachute Creek. Plans for commercialization have not matured since 1974.^{2,3} At one time, TOSCO II technology was envisioned for each of the four federal oil shale tracts.

As envisioned by TOSCO for a 66,000 TPD facility, the pyrolysis and oil recovery unit comprises six individual retorting trains, each capable of processing 11,000 TPD of raw shale. A schematic drawing of a single retorting train is shown in Figure 4-16."

Crushed raw shale feed of particles less than one-half inch in size are conveyed from fine-crushed-ore storage to surge hoppers in the retort section. From the surge hoppers, the raw shale is fed to a dilute phase fluidized bed where it is preheated to about 500°F by direct heat exchange with hot flue gas

¹The venture name was changed to the Colony Development Operation when Atlantic Richfield joined the venture in 1969. Later, Ashland Oil Company and Shell Oil Company replaced Sohio and Cliffs

²Prien, C. H. "TOSCO II Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. p. 37.

³Schora, F. C., P. B. Tarman and H. L. Feldkirchner. "State-of-the-Art - Above Ground Shale Processing", Hydrocarbon Processing 56 (2): 113-119, February 1977.

⁴Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-5, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. pp. IV-42 to IV-44.

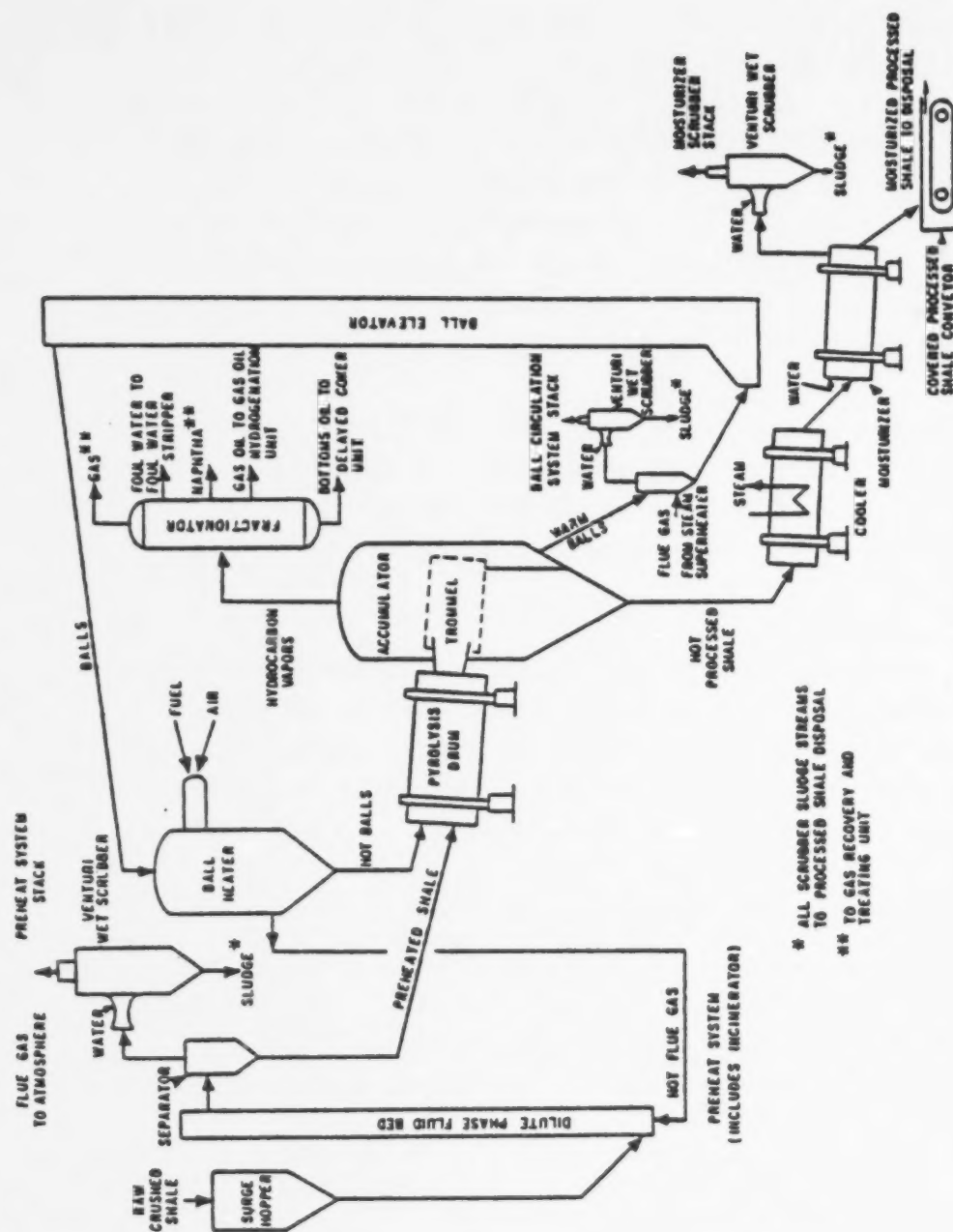


Figure 4-16. Pyrolysis and Oil Recovery Unit TOSCO II Process.

Source: U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado. Draft Environmental Impact Statement. DES-75-62. Washington, D.C. December, 1975. p. II-27

from the ball heater. The preheated raw shale is separated from the flue gas in settling chambers and cyclones and sent to a rotating drum retort.^{1,2}

Hot flue gas is incinerated within the preheat system to reduce trace hydrocarbons to less than 90 parts per million in the discharge flue gas. After heat exchange with the raw shale, the cooled flue gas is passed through dry cyclones and a high-energy venturi wet scrubber to remove shale dust. The cooled flue gas is then vented to the atmosphere at a temperature of approximately 125°F to 130°F. The venturi scrubbers produce an effluent stream of raw shale dust in water. This stream is clarified, with a portion of the water recycled to the scrubbers. Thickened sludge produced in the clarifier is placed on the processed-shale conveyor for disposal in the processed-shale embankment.³

Pyrolysis occurs in the retort by solid-to-solid heat exchange between the preheated shale and hot ceramic balls. The balls are heated to about 1300°F in a vertical ball heater and then fed to the retort to mix with the preheated shale. About one and one-half to two tons of ceramic balls are mixed with every ton of preheated shale. The mixture of balls and shale flows through the retort, where the shale is pyrolyzed at a temperature of about 900°F. An internal pressure of 5 psig is maintained to prevent the entrance of air. Hydrocarbon vapors

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. pp. IV-42 to IV-44.

²Prien, C. H. "TOSCO II Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. p. 37.

³Ashland Oil, Inc. and Shell Oil Co., *op.cit.*

produced from pyrolysis are recovered in an oil recovery system, leaving a residual mixture of balls and processed shale.^{1,2}

The rotating retort is essentially a ball mill: as the kerogen decomposes, the oil shale loses strength and is disintegrated by the ceramic balls. Approximately 4-5% carbonaceous material remains on the shale. The mixture of balls and shale leaves the retort and passes over a rotating trommel screen which separates the balls from the processed shale.³

Flue gas from the stack of a steam superheater is used to entrain residual dust from the balls before they are recycled. The dust is removed from the flue gas with cyclones and a high-energy venturi wet scrubber. The ceramic balls are then recycled to the vertical ball heater by a bucket elevator.⁴

The processed shale is cooled to about 300°F in a rotating drum steam generator. The product steam enters the plant utility system. The cooled processed shale is moisturized to approximately 14 weight percent moisture in a rotating-drum moisturizer to minimize fugitive dust and insure proper handling and compaction

¹Prien, C. H. "TOSCO II Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. p. 37.

²Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 24

³Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-5, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. pp. IV-42 to IV-44.

⁴*Ibid.*

characteristics. Wastewater can be used to moisturize the processed shale. Steam produced during moisturizing contains shale dust which is recovered in a venturi wet scrubber before the steam is discharged to the atmosphere. The processed shale is then conveyed to a disposal site. Dust collected from the various venturi scrubbers throughout the process is also routed to a disposal site with the processed shale.¹

In the oil recovery section of this unit, hydrocarbon vapors are separated by fractionation into gas, naphtha, gas oil, bottoms oil and water. The gas and naphtha streams are sent to the gas recovery and treating unit for gas treating and naphtha stabilization. The gas oil is sent to the gas-oil hydrogenation unit. The bottoms oil is sent to the delayed-coker unit. Moisture in the gas stream is condensed and sent to the foul-water stripping unit for the removal of absorbed ammonia and hydrogen sulfide. The stripped water is used in the pyrolysis unit for moisturizing processed shale.²

Process heaters in the pyrolysis unit can be designed to burn either treated fuel gas, liquid C₄'s, or fuel oil produced in the plant.³

Crude shale oil produced via the TOSCO II process has properties similar to those shown in Table 4-50. The properties of component shale oils are shown in Table 4-51. The TOSCO II process recovers substantially 100% of the recoverable hydrocarbon in oil shale as determined by Fischer assay.

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-6, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. pp. IV-42 to IV-44.

²*Ibid.*

³*Ibid.*

TABLE 4-50. SUMMARY OF PROPERTIES OF CRUDE SHALE OIL
PRODUCED BY TOSCO II PROCESS

Gravity	21.2°API
Specific Gravity (60° F/60° F)	0.927
Pour Point	80°F
	27°C
Viscosity	22 centistokes
	106 SUS at 100°F
Elemental Composition (by weight)	
Carbon	85.1%
Hydrogen	11.6%
Nitrogen	1.9%
Oxygen	0.8%
Sulfur	0.9%
C/H Ratio	7.34
Oil Recovery (% of Fischer)	100
ASTM Distillation	
Initial Boiling Point, °F	100
10% over	200
20% over	275
30% over	500
40% over	620
60% over	775
70% over	850
80% over	920

Source: Hendrickson, T.A. "Oil Shale Processing Methods." Quarterly of the Colorado School of Mines. No. 69, April 1974, pp. 45-69.

Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Engineering Division. June 1976. p. 153.

TABLE 4-51. PROPERTIES OF CRUDE SHALE OIL PRODUCED BY
TOSCO II PROCESS

Component	Vol. %	°API	Wt %	
			S	N
C ₅ -400	17	51	0.7	0.4
400-950	60	20	0.8	2.0
950 +	23	6.5	0.7	2.9
Total	100	21	0.7	1.9

Note: Properties shown in total row are those for composite crude shale oil.

Source: Whitcombe, J. S. and R. G. Vawter "The TOSCO II Oil Shale Process." In: Science and Technology of Oil Shale. T. F. Yen (ed.) (Ann Arbor, Michigan: Ann Arbor Science Publishers, Inc., 1976) p. 51.

An advantage of indirect heating rather than direct gas combustion is that the fuel gas is not diluted by combustion products and consequently has a higher heating value. Approximately 900 scf of gas per barrel of product oil are produced from the TOSCO II retort. The gas has an approximate heating value of 900 Btu/scf. Gas produced in the TOSCO II retorting process has a composition comparable to that shown in Table 4-52.¹

4.6.1.1b Institute of Gas Technology Hydrogasification Process

The Institute of Gas Technology (IGT) began work on their current process in 1972 with laboratory and bench-scale work.

¹Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, TX.: Radian Corporation, September 1977. p. 40.

TABLE 4-52. TOSCO II SEMIWORKS PLANT COMPOSITION
OF C₄ AND LIGHTER GAS

Component	Weight Percent
H ₂	1.50
CO	3.15
H ₂ S	5.16
CO ₂	33.08
CH ₄	11.93
C ₂ H ₄	8.67
C ₂ H ₆	8.43
C ₃ H ₆	11.08
C ₃ H ₈	5.45
C ₄ 's	11.19
Total	100.00

Source: Whitcombe, J. A. and R. G. Vawter. "The TOSCO-II Oil Shale Process". In: Science and Technology of Oil Shale. T. F. Yen (ed.). (Ann Arbor, Michigan: Ann Arbor Science Publishers, Inc. 1976) p.52

Work now includes laboratory and large-scale work in a 1-ton/hour shale feed process development. Earlier laboratory and bench-scale work was performed from 1959 to 1964 on a predecessor process.¹

A flow diagram of the IGT process is shown in Figure 4-17. The key feature of the IGT retort is a moderate-pressure hydrogen atmosphere. Existing screw feed-discharge systems can feed shale

¹Schora, F. C., P. B. Tarman and H. L. Feldkirchner. "State-of-the-Art - Above Ground Shale Processing", Hydrocarbon Processing. 56 (2): 113-119, February 1977.

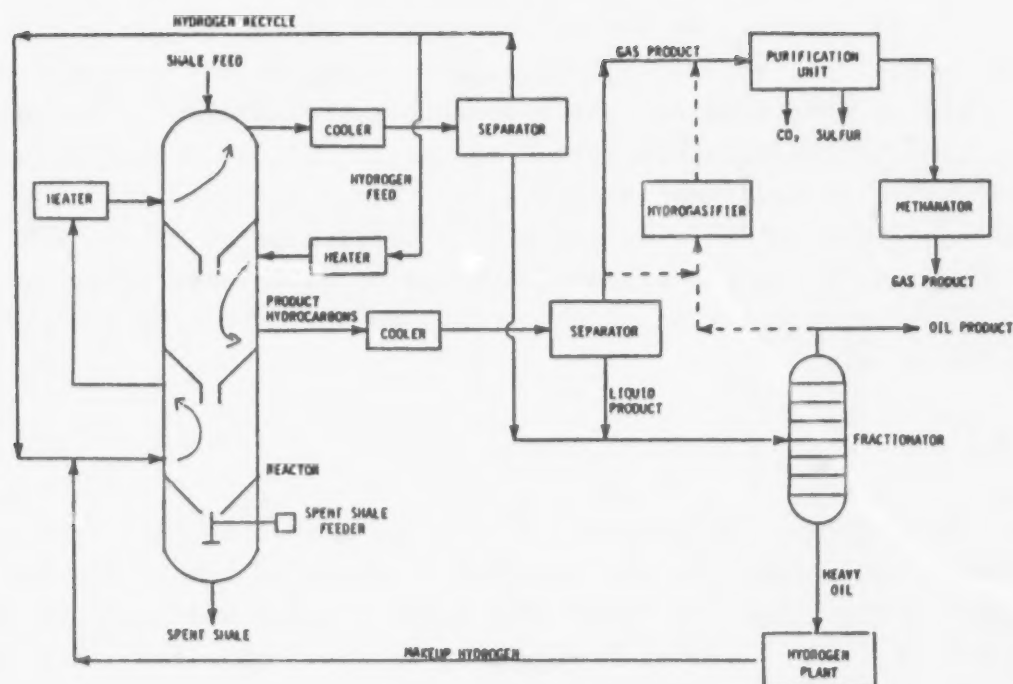


Figure 4-17. Flow Diagram of Institute of Gas Technology Oil Shale Process.

Source: Jones, D. C., et al. Monitoring Environmental Impacts of the Coal and Oil Shale Industries: Research and Development Needs. Austin, TX.: Radian Corporation. Prepared for Environmental Monitoring and Support Laboratory, U.S. Environmental Protection Agency. February 1977.

particles as large as one-half inch. The vertical retort is internally divided into three zones. Shale passing downward is prehydrogenated and preheated in the top zone, hydrotreated in the middle zone, and cooled in the bottom zone. One hydrogen stream picks up some heat from the processed shale and, after additional heating, is used to preheat incoming raw shale. A second hydrogen stream is internally heated and passes through the middle retorting zone to hydroretort the kerogen. Varying the reaction temperature varies the ratio of liquid to gaseous products. If the temperature is maintained below 1200°F, the principal product will be oil with a boiling point below 730°F. Properties of the oil product obtained at 1400°F are shown in Table 4-53. Properties of the processed shale residue are shown in Table 4-54.^{1,2}

4.6.1.1c Paraho Oil Shale Process

Development Engineering, Inc. (DEI) developed the Paraho process, and served as the operating company of the Paraho Development Corporation. A Paraho Oil Shale Project was launched in 1973 with funds provided by 17 participating companies. DEI continued as the operating company.¹

¹Jones, D. C., et al. Monitoring Environmental Impacts of the Coal and Oil Shale Industries: Research and Development Needs, Prepared for Environmental Monitoring and Support Laboratory, U.S. Environmental Protection Agency. Austin, TX.: Radian Corp., February 1977. p. 75.

²Schora, F. C., et al. "Process Shale to SNG," Hydrocarbon Processing. April 1977. pp. 107-110.

³Nevens, T. D. and C. H. Prien. "Paraho Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 17-36.

TABLE 4-53. PROPERTIES OF SHALE OIL OBTAINED FROM
HYDRORETORTING IN IGT'S BENCH-SCALE UNIT

Reactor pressure, psig	500
Product oil properties	
Ultimate analysis, wt% (dry and solids-free basis)	
Carbon	84.44
Hydrogen	11.64
Sulfur	0.50
Nitrogen	1.74
Ash	0.00
C/H weight ratio	7.25
Density, °API	24.0
Distillation, °F	
Initial boiling point	234
End point	761
Recovery, %	89

Source: Schora, F. C., et al. "Process Shale to SNG," Hydro-carbon Processing. April 1977. pp 107-110.

TABLE 4-54. PROPERTIES OF PROCESSED SHALE RESIDUE OBTAINED
FROM HYDRORETORTING IN IGT'S BENCH-SCALE UNIT

Ultimate Analysis (dry), wt%	
Organic carbon	1.18
Mineral carbon	2.10
Hydrogen	0.13
Nitrogen	0.50
Oxygen	5.19
Sulfur	0.25
Ash	91.10

Source: Schora, F. C. et al. "Process Shale to SNG," Hydro-carbon Processing. April 1977. pp 107-110.

The Paraho retort is a variant of a gas combustion retort developed by the U.S. Bureau of Mines from 1945-1955. Six petroleum companies operated a large-scale development of the U.S.B.M. gas combustion retort in 1964-1967 through a lease agreement with the Colorado School of Mines. The consortium of petroleum companies concluded that commercial scale-up of the U.S.B.M. retort was unjustified. Specific difficulties were encountered with small shale sizes, high rates of gas and shale throughput, and bridging due to rich shales.¹ The Paraho and Petrosix² retorts were conceived to overcome problems encountered during testing of the U.S.B.M. retort.

Two newly-designed Paraho retorts have been operated on an intermittent basis from mid-1974 to the present. These include a small pilot plant for rapid investigation of operating parameters, and a 450 TPD semi-works unit for large-scale testing under production conditions.³ An Environmental Impact Statement is now being completed for the construction of a full-scale 7,000 TPD modular Paraho retort and supporting facilities.

¹Prien, C. H. "USBM Gas Combustion Process". Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 73-85.

²Schora, F. C., P. B. Tarman, and H. L. Feldkirchner. "State of the Art - Above Ground Shale Processing," Hydrocarbon Processing 56 (2): 113-119, February 1977.

³Nevens, T. D. and C. H. Prien. "Paraho Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 17-36.

The Paraho retort is capable of using either internal or external heating to achieve the required retorting temperature. In the "direct mode" (i.e., using internal gas combustion) the carbonaceous residue on the retorted shale is burned in the combustion zone of the retort to provide the principal heat for the process. Low-Btu gases and air are recycled to both the combustion zone and the residue and gas preheating zone (as shown in Figure 4-18).¹

In the indirect mode (i.e., using external heat generation), heat for retorting is supplied by hot retort gases heated in an outside furnace (as shown in Figure 4-19). Off-gas produced during retorting has a high heating value (about 900 Btu/scf).²

In either mode of operation, raw shale sized one-quarter to three inches is fed into the top of the retort by a rotary pant-leg distributor, and passes downward by gravity successively through a mist formation and preheating zone, a retorting zone, either a combustion zone (direct mode) or heating zone (indirect mode), and finally, a residue cooling and gas preheating zone. The shale is discharged through a hydraulically-operated grate which controls the downward velocity and maintains even flow across the retort. This grate, the rotary feed mechanism, and the multi-levels of heat input are among the unique contributions of Paraho technology toward improving the retorting principle in vertical-kiln type retorts.³

¹Nevens, T. D. and C. H. Prien. "Paraho Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 17-36.

²*Ibid.*

³*Ibid.*

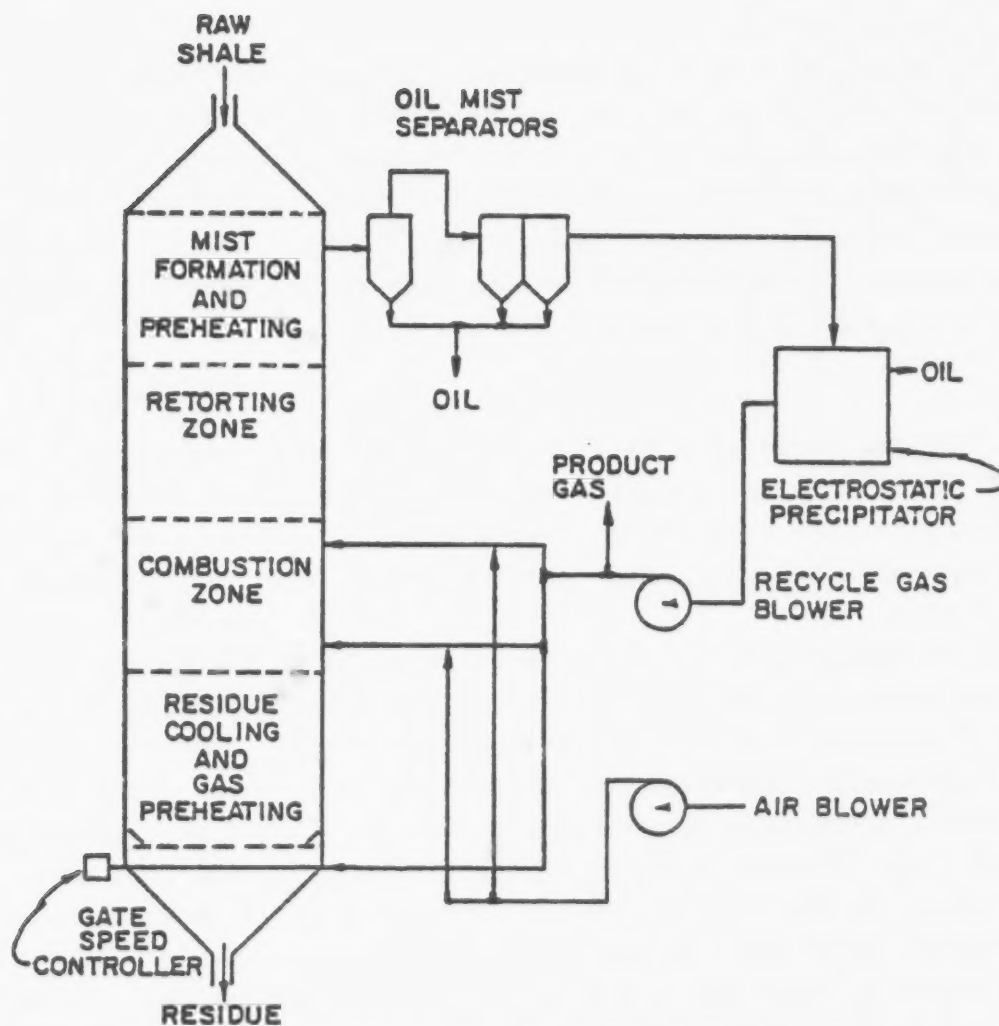


Figure 4-18. Paraho Direct Mode Flow Diagram.

Source: Nevens, T. D. and C. H. Prien. "Paraho Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 17-36.



-159-

The retorted shale, containing about 2% carbon (direct mode) to 4.5% carbon (indirect mode), is discharged from the retort at about 300°F. The processed shale is then moisturized and sent to a disposal area.¹

The shale vapors produced in the retorting zone are cooled to a stable mist by the incoming raw shale (which is thereby preheated), and leave the retort at approximately 140°F. This mist is sent to a roughing cyclone, a condenser, and finally a wet electrostatic precipitator for oil separation. The resulting shale oil is transported to storage.²

In the direct mode, the remaining cooled, oil-free retort gases (approximately 100 Btu/scf) are, in part, used to cool the retorted shale on the grate in the lower "residue cooling and gas preheating zone." Some of the remaining gases are recycled to several levels to dilute the air entering the retort for combustion. The remaining portion of the retort gases are cleaned of H₂S and NH₃ and used as plant fuel or for power generation in low-Btu turbines. From 28 gal/ton shale, 6200 scf of product gases are produced per ton of shale.³

In the indirect heating mode the mist-laden off-gases leave the retort at 280°F. After oil separation, the oil-free recycle gases have a high heating value (about 900 Btu/scf). Part of these gases are reheated in an outside heater and distributed

¹Nevens, T. D. and C. H. Prien. "Paraho Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 17-36.

²*Ibid.*

³*Ibid.*

to the retort at several levels. These hot gases supply the necessary heat for retorting the shale. No residual carbon on the retorted shale or gas is burned in the retort. There is, therefore, no dilution of off-gases with combustion products and resulting reduction in retort-gas heating value.¹

The fuel for the external recycle-gas heater may be a side-stream of the recycle gas itself, or an outside fuel. If the recycle gas is used as fuel, there is a net production of 500 scf/ton of high-Btu gas from 28 gal/ton shale.²

Selected properties of the Paraho shale oils from both direct and indirect modes of operation are shown in Table 4-55. Oil produced via the direct mode has essentially the characteristics of conventional gas combustion-type raw shale oil. Oil produced via the indirect mode has a somewhat lower pour point than that reported for other indirectly-heated retorts. Further lowering of the pour point would require coking.³

The composition of the retort gases from direct and indirect modes of operation are shown in Table 4-56.

¹Nevens, T. D., and C. H. Prien. "Paraho Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 17-36.

²*Ibid.*

³*Ibid.*

TABLE 4-55. PROPERTIES OF PARAHO SHALE OILS

	Heating Mode	
	Direct	Indirect
Gravity, °A.P.I.	21.4	21.7
Viscosity, SUS @ 130°F	90	68
SUS @ 210°F	46	42
Pour Point, °F	85	65
Ramsbottom carbon, wt %	1.7	1.3
Water Content, vol %	1.5	1.4
Solids, B.S., wt %	.5	.6

Note: Data from semi-works retorting of 28 GPT shale, at 97% Fischer assay yield.

Source: Jones, John B., "The Paraho Oil Shale Retort," 81st Nat. Mtg., A.I.Ch.E., Kansas City, Mo., April 11-14, 1976.

4.6.1.1d Union Oil Shale Retorting Process

The development of Union's oil shale technology was initiated in the early 1940's. Several versions of a vertical kiln retorting process with upward flow of shale and countercurrent downward flow of gases and liquids have been developed. The first concept, the Retort A process, was demonstrated at rates of 700-1000 TPD, with a peak rate of 1200 TPD. Although the demonstration of the Retort A process was successful, the Union Oil work was suspended due to a plentiful supply of low-cost Middle East oil and natural gas. An improved version of the Union Oil process, the Retort B process, has been developed through the pilot plant stage. Union Oil has proposed the construction and demonstration of the Retort B process on a commercial plant processing 10,000 TPD shale.¹

¹Shih, C. C. "Union Oil Shale Retorting Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 5-15.

TABLE 4-56. COMPOSITION OF PARAHO RETORT GASES

Component	Direct Mode	Indirect Mode
	Composition by Volume	
H ₂	2.5%	24.8%
N ₂	65.7%	0.7%
O ₂	0 %	0 %
CO	2.5%	2.6%
CO ₂	24.2%	15.1%
CH ₄	2.2%	28.7%
C ₂ H ₄	0.7%	9.0%
C ₂ H ₆	0.6%	6.9%
C ₃	0.7%	5.3%
C ₄	0.4%	2.0%
H ₂ S	2660ppm	3.5%
NH ₃	2490ppm	1.2%
High Heating Value, (Btu/scf)	102	885
High Heating Value, (kcal/m ³)	908	7560
Retort Gas Yield, (scf/ton)	6200	500
Retort Gas Yield, (m ³ /10 ³ kg)	193	15.6

Note: Data from semi-works retorting of 28 GPT oil shale,
at 97% Fischer assay yield.

Source: Jones, John B., "The Paraho Oil Shale Retort", 81st
Nat. Mtg., A.I.Ch.E., Kansas City, Mo., April 11-14,
1976.

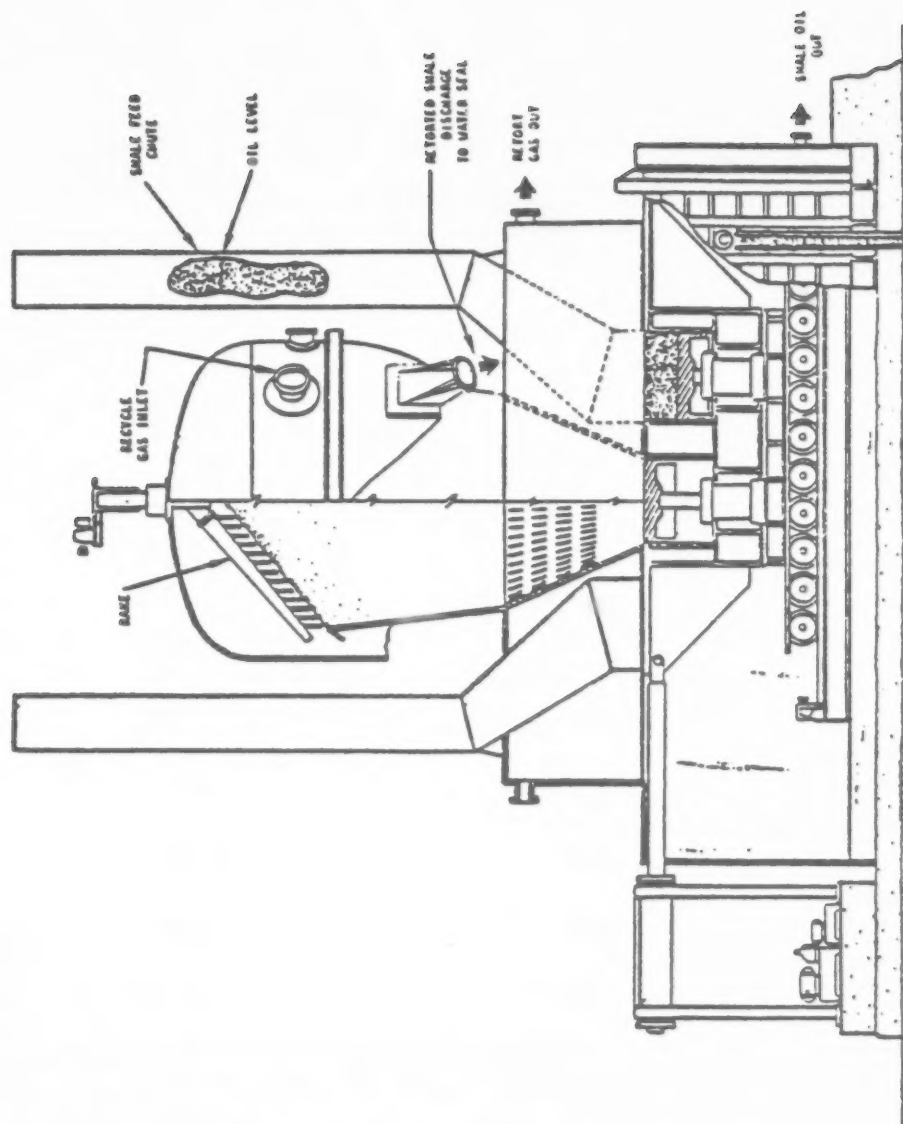


Figure 4-20. Union Retort B.

Source: Hopkins, J. M., H. C. Huffman, A. Kelley, and J. R. Pannall. "Development of Union Oil Company Upflow Retorting Technology." Presented at the 81st AIChE National Meeting, April 11-14, 1976, Kansas City, Missouri.

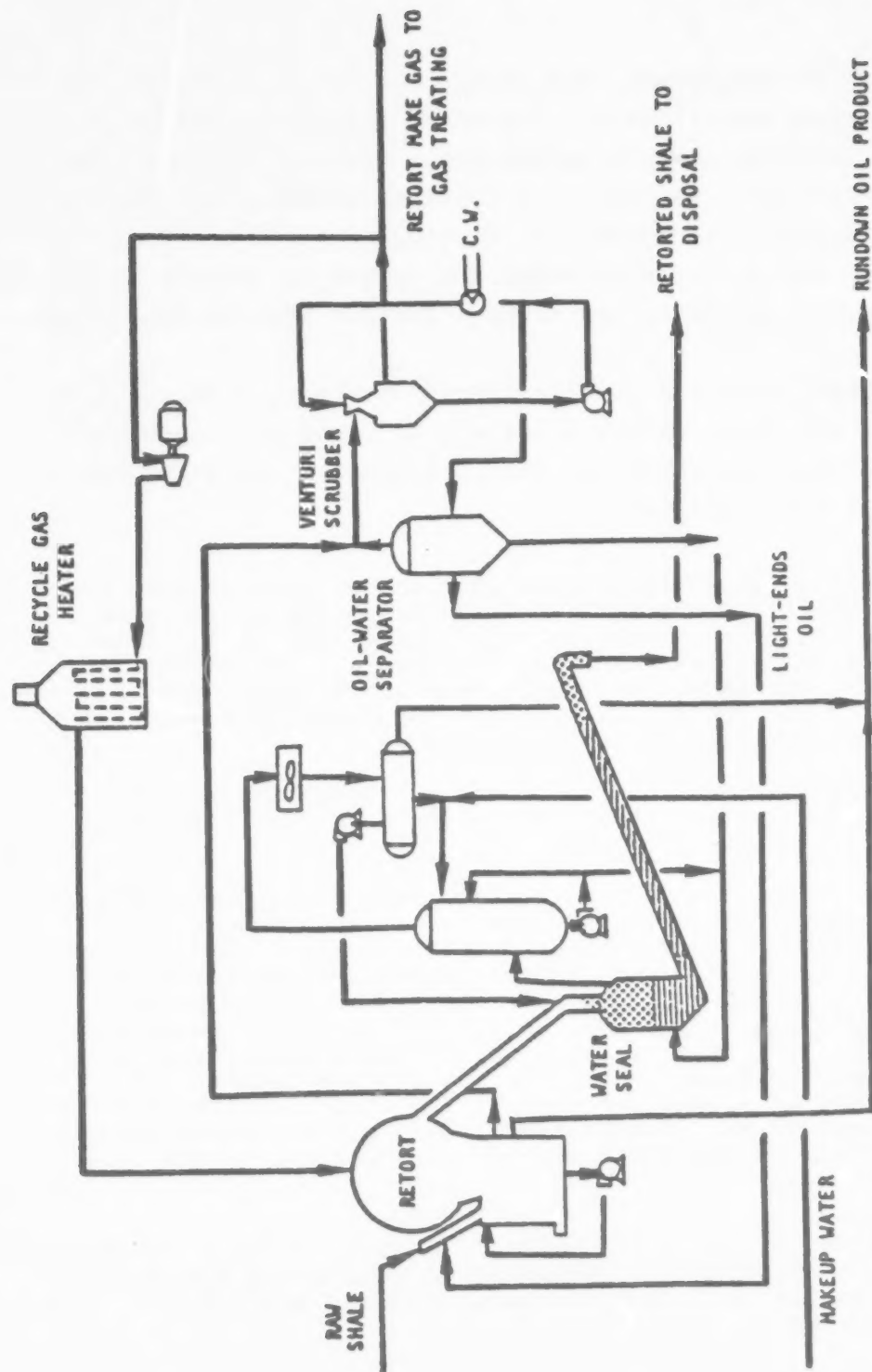


Figure 4-21. Union Retort B Flow Diagram.

Source: Hopkins, J. M., H. C. Huffman, A Kelley, and J. R. Pawnall. "Development of Union Oil Company Upflow Retorting Technology." Presented at the 81st AIChE National Meeting, April 11-14, 1976, Kansas City, Missouri.

An auxiliary process, SGR (Steam Gas Recirculation), has also been examined by Union. Processed shale from Retort B contains a nominal 4 wt. % carbonaceous deposit. In SGR, the hot processed shale is sent to a separate vessel where the carbonaceous deposit is removed by reacting with steam and air to produce low-Btu gas or with steam and oxygen to produce high-Btu gas. Marginal economics has stopped further work on this process.¹

The Union Retort B is illustrated in Figure 4-20. A flow diagram of the Union Retort B process is found in Figure 4-21. A detailed description of the Retort B process, as presented by Hopkins (et al)², follows.

Oil shale (sized from one-eighth to two inches) from the feed bin flows through two...chutes to the solids pump. Shale oil product acts as a hydraulic seal in the feed chutes to maintain the retort pressure. The solids (rock) pump is mounted on a movable carriage...and consists of two piston and cylinder assemblies which alternately feed shale to the retort.

The shale is retorted as it rises through the retort cone. (Heat is supplied by a countercurrent flow of hot recycle gas.)

The space above the cone is enclosed by the dome. The (processed) shale slides down chutes and through the dome wall at the (processed) shale outlets. Hot recycle gas is introduced into the space between the (processed) shale pile and the dome. It flows downward into the rising shale to provide the heat required for retorting.... The bulk of the liquid product trickles down through the cool, incoming shale and the balance, in the form of a mist, is carried from the retort by the (cooled) gases. The gas and liquid are separated from the shale in the lower slotted wall section of the retort cone.

¹Hopkins, J. M., H. C. Huffman, A. Kelley, and J. R. Pownall. "Development of Union Oil Company Upflow Retorting Technology", Presented at 81st A.I.Ch.E. National Meeting, April 11-14, 1976, Kansas City, Mo.

²*Ibid.*

The shale particles which fall through the slots into the disengaging section are recycled to the feed chutes. The retorted shale is conveyed in pipes to one of the two retorted shale cooling vessels. As shown in Figure (4-21), a level of shale is maintained above the level of water in the quench vessel. A drag chain conveyor removes the cooled shale from under the water level. A water level is maintained in the conveyor to seal the retort from the atmosphere. Generated steam is condensed and returned to the cooling vessel. The cooled and (moistened) processed shale is sent to disposal.

Gases from the disengaging section are scrubbed and cooled in a venturi scrubber. Agglomerated mist plus light ends and water produced by cooling are sent to an oil-water separator. The oil is recycled to the retort through the oil shale feed line and the water is sent to the water seal after stripping to remove ammonia. The scrubbed gas is divided into a make stream and a recycle stream. The recycle stream is compressed and heated prior to injection into the top of the retort.

The make gas is processed by compression and scrubbing to remove heavy ends and hydrogen sulfide. Oil is used to scrub out the heavy hydrocarbons and Stretford solution is used to remove hydrogen sulfide. The sweetened make gas is used as plant fuel.

The liquid product from the retort is treated sequentially to remove solids, arsenic and light ends. Solids removal is accomplished by two stages of water washing. The shale fines are collected in the water phase which is recycled to the water seal.

The liquid product contains 50 ppm of chemically combined arsenic. (The arsenic concentration is) reduced to about 2 ppm in a proprietary Union Oil process. (The process uses) an absorbent which picks up arsenic to about 80 percent of its weight. About 50 tons of spent absorbent will be placed in the retorted shale disposal area per year. The dearsenated shale oil is sent to a stripping column for stabilization and sweetening prior to upgrading.

Make gas production from the retort will exceed plant fuel requirements. To avoid flaring the excess, the system will be balanced by absorbing the heavy ends of the make gas into the oil product. This will be accomplished by varying the operating conditions of the stripping column and a related debutanizer.

Properties of shale oil produced from the Retort B process are shown in Table 4-57. Union Oil indicates that a high-quality crude shale oil is obtained in the Retort B process because oil vapor evolved in the retort is quickly forced downward by the gas toward the cooler shale, thus quenching the polymerization reactions which form difficult-to-refine heavy oil. In addition, the use of an indirectly heated recycle gas in the Retort B process appears to cause a lower oxygen content in crude shale oil. This is desirable because the presence of oxygen compounds contributes to gum formation and enhances corrosion rates in certain situations.¹

Upgraded product gas from the Union B retort has a heating value of about 800 Btu/scf.²

4.6.1.1e Lurgi-Ruhrgas Process for Oil Shale Retorting

Lurgi has been developing oil shale processing technology for the past 40 years. Two kilns were designed and installed

¹Hopkins, J. M., H. C. Huffman, A. Kelley, and J. R. Pownall. "Development of Union Oil Company Upflow Retorting Technology", Presented at 81st AIChE National Meeting, April 11-14, 1976, Kansas City, Mo.

²Shih, C. C. "Union Oil Shale Retorting Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 5-15.

TABLE 4-57. PROPERTIES OF UNION RETORT B CRUDE OIL

Gravity (60 F/60°F)	0.918
	22.7°API
Pour Point	60°F
Viscosity at 100°F	20 centistokes
	98.2 SUS
Elemental Composition (by weight)	
Carbon	84.8%
Hydrogen	11.61%
Nitrogen	1.74%
Oxygen	0.90%
Sulfur	0.81%
C/H Ratio	7.30
Fischer Assay of Feed (gpt)	24.2
Oil Recovery (% of Fischer Assay)	91.0
ASTM Distillation	
Initial Boiling Point	139°F
10% Over	400°F
50% Over	731°F
90% Over	960°F
End Point	1077°F

Source: Hendrickson, T. A., Comp. Synthetic Fuels Data Handbook
Denver, Colorado: Cameron Engineers, Inc. 1975

for an Estonian Shale Oil Company in the late 1930's. Several other oil shale retorting processes were also developed by Lurgi to the commercial stage.¹

The Lurgi-Ruhrgas Process was developed in the 1950's for the low-temperature carbonization of subbituminous coal. It has also been used for olefin production using sand as the heat carrier. The process was demonstrated commercially in two units built in Yugoslavia in 1963. Tests on oil shale have been performed in equipment processing 16 TPD. American Lurgi has proposed scale-up to 8000 TPD commercial-size retorts. Eight such plants can provide capacity for the production of 50,000 BPD shale oil.^{2,3}

The Lurgi-Ruhrgas process is illustrated in Figure 4-22. Oil shale crushed to sizes less than 1/3 in. is fed to the screw mixer. The raw shale is heated to about 990°F by mixing with six times as much hot processed shale from the separating bin. Retorting occurs in the screw mixer. The shale mixture is then dropped from the screw mixer into a surge hopper where residual oil components are distilled off.^{4,5}

¹Shih, C. C. "The Lurgi-Ruhrgas Process for Oil Shale Retorting", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 55-61.

²Schora, F. C., P. B. Tarman and H. L. Feldkirchner. "State-of-the-Art - Above Ground Shale Processing", Hydrocarbon Processing. 56 (2): 113-119, February 1977.

³Marnell, P. "Lurgi/Ruhrgas Shale Oil Process", Hydrocarbon Processing 55 (9): 269-271, September 1976.

⁴*Ibid.*

⁵Shih, C. C., *op.cit.*

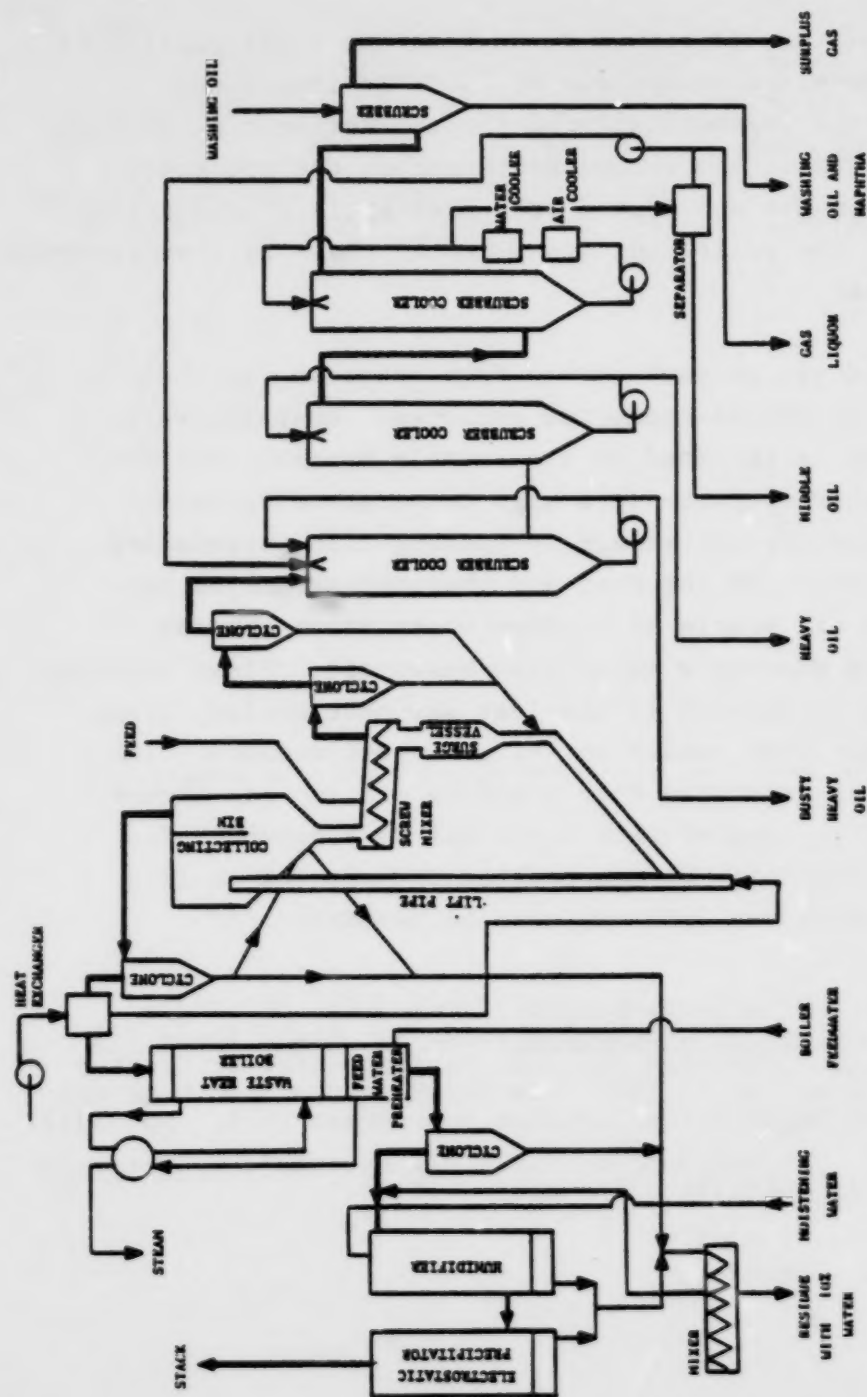


Figure 4-22. The Lurgi-Ruhrgas Process for the Retorting of Oil Shale.

Source: Schmalfeld, P. "The Use of the Lurgi-Ruhrgas Process for Distillation of Oil Shale." Quarterly of the Colorado School of Mines 70(3): 129-145, July 1975.

The shale mixture is passed through to the lower section of the lift pipe where combustion air at 750°F is introduced, raising the mixture pneumatically to the collecting bin, while simultaneously burning the carbon contained on the processed shale. Combustion gas and heated processed shale at about 1200°F are separated in the collecting bin. Heated shale is then returned to the screw mixer.^{1,2}

The volatile gas product stream from retorting is then passed through two series-connected cyclones. Dust separated in these cyclones is returned to the recycle system. The first gas scrubber-cooler operates at a high temperature to remove residual dust from the gas stream by washing with circulating condensed heavy oil. In the next scrubber-cooler, major condensation of the oil occurs at a temperature above the dew point of water to recover a water-free heavy oil. Final cooling uses circulating condensate in the last scrubber-cooler, after the condensate has been cooled in air and water coolers. The condensate is then separated into a middle oil and gas liquor. Finally, the gas is treated with light oil in a scrubber for the recovery of naphtha. By compressing the gas and cooling it to lower temperatures, LPG can also be recovered.^{3,4}

¹Shih, C. C. "The Lurgi-Ruhrgas Process for Oil Shale Retorting", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 55-61.

²Marnell, P. "Lurgi/Ruhrgas Shale Oil Process", Hydrocarbon Processing 55 (9): 269-271, September 1976.

³*Ibid.*

⁴Shih, C. C., *op.cit.*

Combustion gases evolved in the lift pipe are cleaned in a cyclone after leaving the collecting bin. Part of the entrained dust can be returned to the collecting bin (if necessary). The gas stream is then routed through a heat exchanger (for the preheating of combustion air), a waste heat boiler, a feedwater preheater, another cyclone, a humidifier and an electrostatic precipitator before discharge to the atmosphere. In the humidifier, the flue gas is cooled from 600°F to 300°F by water injection. A portion of the shale dust entrained in the gas is separated and discharged onto a chain conveyor. Residual dust is removed from the flue gas in the electrostatic precipitator and discharged onto another chain conveyor. The two chain conveyors carry the fine dust from the cyclone and the heavy oil dust from heavy oil dust removal. Moistening water and gas liquor are added to the dust in a mixer. The final processed shale residue has a moisture content of 10 to 12% water and a temperature of 150°F.^{1,2}

Final products of the Lurgi-Ruhrgas process include a dust-free heavy oil, a middle oil, a gas naphtha, and a naphtha-free distillation gas. Properties of the products are summarized in Tables 4-58 and 4-59. Quantities of the products are shown in Tables 4-60.

4.6.1.1f Superior Oil Shale Process

The Superior Oil Shale process is unique among current U.S. shale processing methods in two respects, namely, its recovery of saline minerals and its use of a circular grate retort.

¹ Marnell, P. "Lurgi/Ruhrgas Shale Oil Process", Hydrocarbon Processing 55 (9): 269-271, September 1976.

² Shih, C. C. "The Lurgi-Ruhrgas Process for Oil Shale Retorting", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 55-61.

TABLE 4-58. CHARACTERISTICS OF OIL PRODUCTS OF THE
LURGI-RUHRGAS RETORTING PROCESS

	Heavy Oil (dust free)	Middle Oil	Naphtha
Gravity	0.96 (122°F) 0.94 (176°F)	0.82 (68°F)	0.70 (68°F)
Viscosity, SUS	530.0 (122°F) 120.0 (176°F)	33.0 (68°F)	--
Flash point, °F	309.0	<70	--
Settling point, °F	75.0	<-40	--
Conradson, wt %	8.1	0.43	--
Ultimate analysis, wt %			
Carbon	85.6	85.3	84.2
Hydrogen	10.7	12.5	13.2
Sulfur	1.0	0.7	} 2.6
Nitrogen	1.5	0.5	
Oxygen	1.2	0.8	

Source: Rurak, J. R., et al: U.S. Bureau of Mines Report of
Investigation Number 7540, 1971.

TABLE 4-59. PROPERTIES OF DISTILLATION GAS FROM
LURGI-RUHRGAS RETORTING PROCESS

Composition (by volume)		
CO ₂		28.8%
CO		3.1%
H ₂		21.3%
N ₂		8.9%
C ₁		13.7%
C ₂		13.8%
C ₃		10.3%
Other		
H ₂ S	2.28g/Nm ³ (0.94gr/scf)	
SO ₂	0.07g/Nm ³ (0.03gr/scf)	
Net calorific value	7150 Kcal/Nm ³ (760 Btu/scf)	

Source: Schmalfeld, P. "The Use of the Lurgi-Ruhr gas Process for the Distillation of Oil Shale." Quarterly of the Colorado School of Mines. 70(3): 129-145, July 1975.

TABLE 4-60. PRODUCTS OF THE LURGI-RUHRGAS
RETORTING PROCESS

Basis: Shale Oil Production - 50,000 BPD
Oil Shale Quality - 30 gal/ton
Oil Yield - 104.5% Fischer Assay

Feed

Shale Feed	2931 tons/hr
------------	--------------

Products

Heavy oil (dedusted)	449 barrels/hr
Middle oil	1405 barrels/hr
Naphtha	259 barrels/hr
Gas (640 Btu/ft ³)	2.12 MM ft ³ /hr

Waste Products

Processed Shale	2428 tons/hr
Gas Liquor	51 tons/hr

Note: Gas liquor can be treated to remove phenols, ammonia, and other impurities and used in the retort section to moisten the processed shale.

Source: Ruark, J. R., et al: U.S. Bureau of Mines Report of Investigation Number 7540, 1971.

Superior Oil began development of its process in 1967 to exploit its privately owned shale deposits which contain, in addition to oil shale, nahcolite (NaHCO_3), and dawsonite ($\text{NaAl}(\text{OH})_2\text{CO}_3$). A pilot plant has been operated at about 100 TPD. Superior plans to build three 20,000 TPD demonstration modules with private funding.^{1,2,3}

The basis of the separation of nahcolite from shale is a difference in friability. Crushing and screening yields nahcolite of about 80% purity. With additional processing, including photosorting of the residue from crushing and screening, purity can be increased to more than 90%. Nahcolite remaining in the shale continues through the retorting process.⁴

The dawsonitic shale from nahcolite recovery is fed to a traveling circular grate retort (see Figures 4-23 and 4-24). The doughnut-shaped retort has five separately-divided sections through which the shale travels in sequence. These are a loading zone, retorting zone, residual carbon recovery zone, cooling zone, and unloading zone. In the retorting zone, shale is pyrolyzed by hot gases to produce liquid and gaseous hydrocarbons. These products are then drawn off and piped to further processing. Any sour water produced in this stage is collected and disposed with processed shale.⁵

¹Schora, F. C., P. B. Tarman and H. L. Feldkirchner. "State-of-the-Art - Above Ground Shale Processing", Hydrocarbon Processing 56 (2): 113-119, February 1977.

²Prien, C. H. "Superior Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 63-74.

³"Prognosis Good for New Shale Oil Process", Chemical and Engineering News. January 10, 1977. pp. 27-28.

⁴*Ibid.*

⁵*Ibid.*

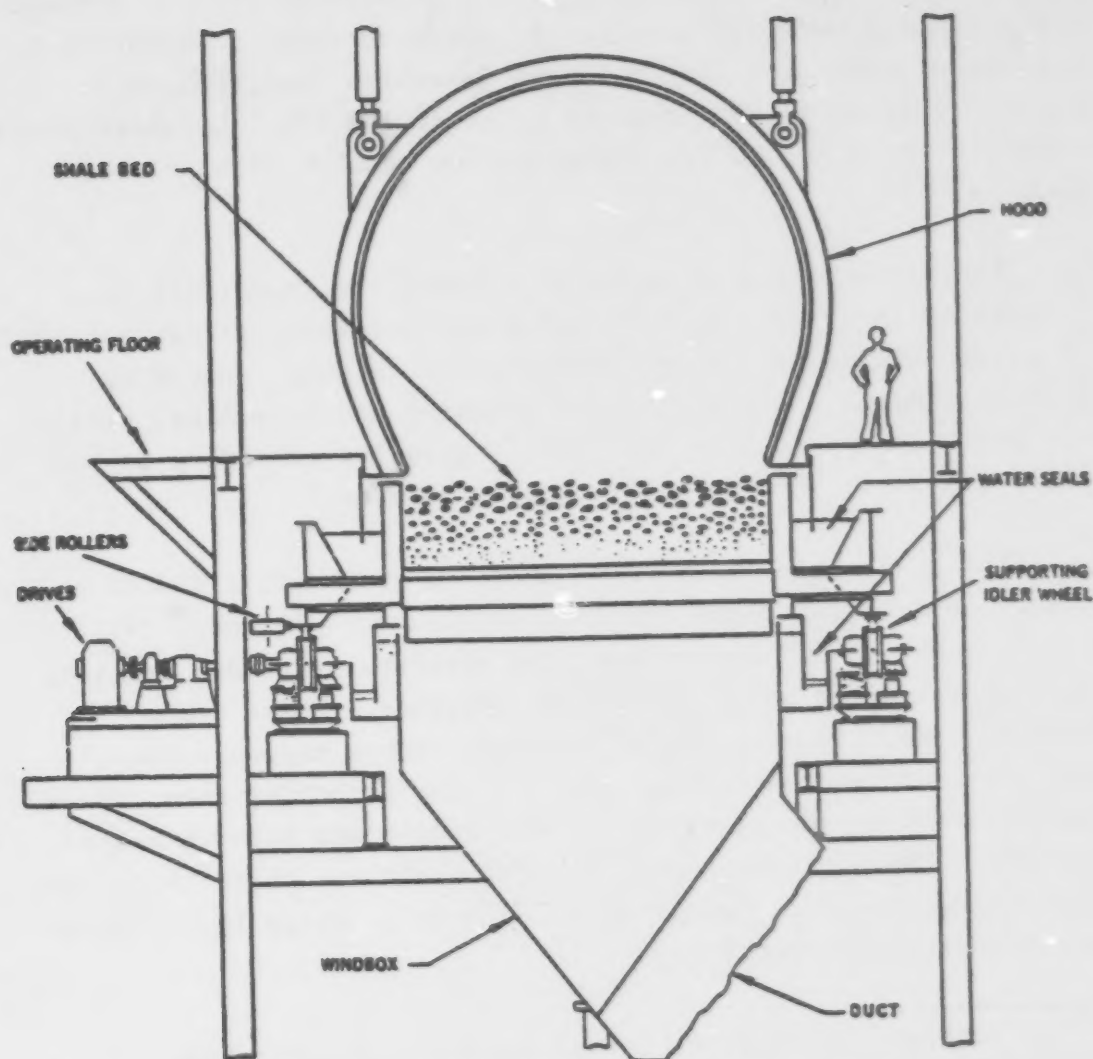


Figure 4-23. Cross Section of Circular Grate Retort.
(Courtesy Arthur G. McKee & Co.)

Source: Prien, C. H. "Superior Oil Shale Process".
Technological Overview Reports for Eight Oil
Shale Recovery Processes. Prepared for U.S.
Environmental Protection Agency. Contract
No. 68-02-1881. Denver Research Institute and
TRW Environmental Engineering Division, December
1976. p. 69.

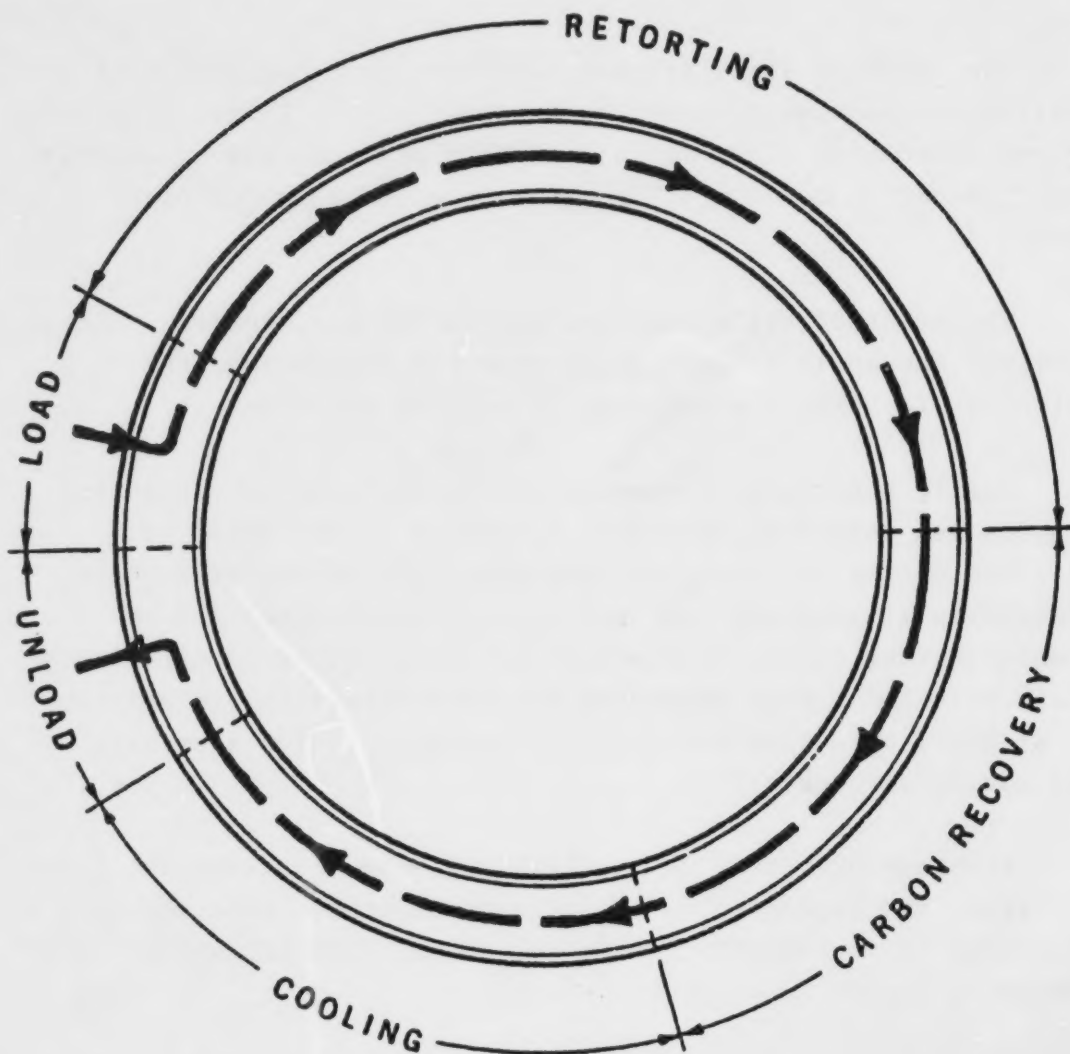


Figure 4-24. Plan View of Circular Grate Retort Showing Movement of Charge through Various Zones.

Source: Prien, C. H. "Superior Oil Shale Process". Technological Overview Reports for Eight Oil Shale Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division, December 1976. p. 70.

The retorted shale travels from the retorting zone to the residual carbon recovery (or combustion) zone. There, the shale is contacted with steam and air to form producer gas by reaction with the carbon residue. The gas is used locally for plant fuel.^{1, 2}

The retorted shale then travels to the cooling zone. After cooling, the shale is discharged from the retort and sent to a leaching plant for the recovery of alumina and soda ash.³

During retorting, dawsonite in the shale is converted to alumina and soda ash. Residual nahcolite in the shale is calcined during retorting to soda ash. Cooled retorted shale containing alumina and soda ash is then crushed and fed to countercurrent decanters where it is dissolved in an alkaline leach solution. Both dawsonite and nahcolite dissolve readily in alkaline solutions to yield solutions of sodium aluminate and sodium carbonate.⁴

Aluminum hydroxide is crystallized from the aluminate liquor, filtered, and calcined into cell-grade alumina. Soda ash is recovered by triple-effect evaporation and centrifugation. Any remaining liquor is recycled.⁵

¹Prien, C. H. "Superior Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 63-74.

²"Prognosis Good for New Shale Oil Process", Chemical and Engineering News. January 10, 1977. pp. 27-28.

³Prien, C. H., *op.cit.*

⁴"Prognosis Good for New Shale Oil Process", *op.cit.*

⁵*Ibid.*

Products from a 25,000 TPD plant are summarized in Table 4-61. Oil is expected to have a gravity of 26°API and a pour point of 70°F. The oil typically contains 2% nitrogen and 0.8% sulfur.¹

TABLE 4-61. PRODUCTS FROM THE SUPERIOR MULTIMINERAL RECOVERY PROCESS

Basis: 25,000 TPD of mined shale

Products	
Shale oil	10,000 - 15,000 BPD
Nahcolite	4,500 TPD
Cell-Grade Alumina	500 - 800 TPD
Soda Ash	800 - 1300 TPD

Source: Prien, C. H. "Superior Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 63-74.

4.6.1.1g Shale Oil Upgrading

Crude shale oils have relatively higher nitrogen contents, viscosities, and pour points than do conventional crude oils. Oxygen and sulfur contents of crude shale oils are comparable to

¹Prien, C. H. "Superior Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 63-74.

those of conventional crudes. Most crude shale oils also contain a large fraction of unsaturated and aromatic compounds, and tend to form gums during storage. Compared to most conventional crude oils, shale oils yield less light ends upon distillation.¹

Crude shale oils also contain ash in the form of raw and retorted shale fines. Most trace elements in shale oil are associated with ash, and concentrate in higher boiling point fractions.^{2, 3}

Because of the above properties, crude shale oil is not readily marketable. Upgrading facilities are required to produce an oil product having reduced sulfur and nitrogen contents. In addition, upgrading is required to reduce the pour point and viscosity of the oil to make it easier to transport by pipeline.⁴

Current oil shale developments do not plan to process crude shale oil into a full range of refined products as is the case

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division, June 1976.

²*Ibid.*

³Arsenic is found in essentially all distillate cuts.

⁴Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. p. IV-38.

with petroleum crude in modern petroleum refineries. Planned upgrading ranges from simple oil/water separation to the production of finished fuels or premium refinery feedstocks. The choice of upgrading schemes depends primarily on economic and market conditions,^{1,2} and on the quality of shale oil produced in the process. Table 4-62 summarizes pre-refining or upgrading operations planned by several oil shale developers.

Two principal options are available for producing marketable shale oil. One is to minimize upgrading and market the raw shale oil as a "synthetic" heavy crude oil or No. 6 fuel oil. The second option is to upgrade or pre-refine shale oil on-site. This would produce an oil suitable for marketing as a No. 2 fuel oil or suitable for direct conversion to finished products (such as gasoline, turbine fuel, home heating oil and petrochemical feedstocks).³

Each option has its own slate of by-products. Minimal refining could yield LPG, coke, and small amounts of sulfur as by-products. More extensive refining could yield LPG, coke, larger quantities of sulfur, and ammonia.⁴

The remainder of this section describes the production of finished fuels to premium feedstocks. Such an upgrading scheme

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency, Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division, June 1976.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. p. IV-38.

³*Ibid.*

⁴*Ibid.*

TABLE 4- 62. SUMMARY OF "ON-SITE" SHALE OIL UPGRADING BY SEVERAL OIL SHALE DEVELOPERS

Developer	Retort Technology	Steps of Upgrading or Pre-refining	Products
Colony Development Operation - Parachute Creek	TOSCO II	• Distillation followed by delayed cooking of residue • Dearsenation of naphtha and gas oil fractions • Catalytic hydrogenation of naphtha and gas oil fractions • Hydrogen production by catalytic reforming of naphtha followed by steam, reforming shift conversion, CO₂ removal	• Low sulfur fuel oil • LPG • Coke • Sulfur • Ammonia
Occidental Oil Shale and Ashland Oil	Occidental modified in-situ	• No upgrading indicated, company indicates oil can be transported directly to refinery	• Crude shale oil • Sulfur from gas treatment
Union Oil	Union Retort B	• Solids/fines removal via filtration and water washing • Catalytic dearsenation • Stripping/stabilization	• Sulfur • Ammonia • Coke • Prerefined shale oil • Shale
Superior	Superior	• Company indicates that blending with petroleum crudes will be attempted.	• Crude shale oil • Sodium bicarbonate • Alumina
Rio Blanco	RISE modified in situ and surface retort (e.g., TOSCO II)	• No upgrading, pipeline quality oil produced by blending oil from surface retort with oil from in-situ retort	• Crude shale oil • Sulfur
Paraho	Paraho	• Delayed coking • Hydrogenation of naphtha and gas oil fractions	• Crude shale oil • Ammonia • Sulfur • Coke
Lurgi-Ruhrgas	Lurgi-Ruhrgas	• Oils fractionated in scrubbing coolers	• Gas naphtha • Heavy oil • Middle oil

Source: Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division, June 1976.

is preferred by Colony Development Operation, and was selected in the original development plan for oil shale tract C-b.^{1,2}

As originally envisioned by the developers of oil shale tract C-b, retorting and upgrading operations produce 45,000 barrels of low-sulfur oil, 4200 barrels of liquefied petroleum gas (LPG), 180 tons of sulfur, and 800 tons of coke from a raw shale feed of 66,000 tons per stream-day. Fuels produced by the plant for internal consumption include treated high-Btu gas, a C₄ liquid (containing butanes, butenes, and some C₃'s), fuel oil, and diesel fuel. Upgrading operations which produce this product slate are described below, as reported in the most recent document describing a TOSCO II retorting and upgrading complex.³ Process units in the upgrading section are 1) Gas Recovery and Treating; 2) Hydrogen Production; 3) Gas-Oil Hydrogenation; 4) Naphtha Hydrogenation; 5) Ammonia Separation; 6) Sulfur Recovery; 7) Delayed Coker; and 8) Foul-water Stripping. A flow-sheet of this upgrading sequence is shown in Figure 4-25. Each of the upgrading units are discussed in turn.

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976.

²U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado. Draft Environmental Impact Statement.

³Ashland Oil, Inc. and Shell Oil Co., *op.cit.*, pp. IV-38 to IV-59.

1) Gas Recovery and Treating

In the gas recovery and treating unit, gas and raw naphtha produced in the oil recovery, coker, naphtha hydrotreater and gas-oil hydrotreater units are separated into fuel gas, liquified petroleum gas (LPG), butanes and a stabilized naphtha. Hydrogen sulfide is removed from fuel gas, LPG and butanes as required for environmental and process considerations. Fuel gas is used as plant fuel and hydrogen plant feed.

LPG is a blend of propane and propylene and can be sold as a product. The butane stream is a mixture of butane and butylene and can be used as plant fuel. Stabilized naphtha is sent to the naphtha hydrotreater for further processing. Process operations in this unit include oil absorption, diethanolamine (DEA) contact, and amine regeneration.

2) Hydrogen Production

Hydrogen is used in the hydrogenation units to remove nitrogen and sulfur from the naphtha and gas-oil streams. The required hydrogen is produced from fuel gas and steam in a conventional steam reforming process.

3) Gas Oil Hydrogenation

The gas-oil hydrogenation unit treats a mixture of gas oil from the pyrolysis and delayed-coker units with hydrogen in the presence of a catalyst to produce a low-nitrogen, low-sulfur gas oil. The treated gas-oil product is blended with treated naphtha product from the naphtha hydrogenation unit to form low-sulfur fuel oil, which can be pipelined from the complex. This unit also produces diesel fuel which is used for mobile equipment in the mine and processed-shale disposal areas.

4) Naphtha Hydrogenation

The naphtha hydrogenation unit treats a stabilized naphtha blend from the gas recovery and treating unit with hydrogen in the presence of a catalyst to produce a low-sulfur, low-nitrogen naphtha. The treated naphtha product is blended with treated gas-oil product from the gas-oil hydrogenation unit to form low-sulfur oil, which can be pipelined from the complex. This unit is quite similar to the gas-oil

hydrogenation unit; however, the lighter naphtha requires less severe hydrogenation conditions than needed for the gas oil.

5) Ammonia Separation

The ammonia separation unit processes sour water from the naphtha and gas oil hydrotreaters. Liquid anhydrous ammonia is produced as a marketable by-product. Gaseous hydrogen sulfide is removed and sent to the sulfur recovery unit and the stripped water is recycled to the hydrotreaters.

6) Sulfur Recovery

The sulfur recovery unit removes and recovers sulfur from the hydrogen sulfide-rich acid-gas streams which emanate from the ammonia separation unit, the foul-water stripper and the gas recovery and treating unit. The function of this unit is to prevent the direct release of sulfur compounds to the atmosphere or the release of SO_2 by open flaring of acid gases. The unit converts these sulfur compounds into marketable liquid sulfur by-products.

Sulfur recovery involves a combination of two units. A Claus unit converts hydrogen sulfide to elemental sulfur, which is recovered. A tail-gas unit oxidizes unconverted hydrogen sulfide and other unrecovered sulfur compounds from the Claus unit to sulfur dioxide, which is then recycled to the Claus plant for further treatment. This tail-gas unit vents to the atmosphere.

7) Delayed Coker

The delayed-coker unit is an upgrading unit which cracks the heaviest oil, known as bottoms oil, from the pyrolysis and oil recovery unit into lighter hydrocarbon products and by-product coke by thermal decomposition. The lighter products are fractionated into gas, naphtha and gas oil. Foul water is also produced from this unit. This water is removed in the fractionator. The major product of this unit is gas oil which is sent to the gas-oil hydrogenation unit for further upgrading. Approximately 35 percent of the bottoms oil is converted to coke.

8) Foul-Water Stripping

The foul-water stripping unit removes H_2S and minor amounts of ammonia (NH_3) from foul-water streams collected from the pyrolysis and oil recovery unit, the gas recovery and treating unit, and the delayed-coker unit. The H_2S and NH_3 are sent to the sulfur recovery unit, where H_2S is converted to elemental sulfur and ammonia is converted to nitrogen. The stripped water is returned to the pyrolysis unit for moisturizing processed shale. The foul-water stripper is a conventional-distillation column with a steam-heated reboiler.¹

The following summarizes the upgrading sequence: Gas from the retort is routed to gas recovery and treating and then recycled to the retort for gas combustion, or sent to the hydrogen production unit. Naphtha is normally stabilized and then hydrotreated. Gas oil streams are also hydrotreated. Bottoms oil from the fractionator is thermally cracked by use of a delayed coker, thus recovering additional oil and producing a coke by-product. All H_2S -rich gas streams are routed to the sulfur recovery unit. Wash water from the hydrotreaters is stripped at an ammonia separation unit. Water removed from gas streams is routed to a foul water stripper to remove ammonia and hydrogen sulfide. The stripped water is used for moisturizing the spent shale.

4.6.1.2 Input Requirements

This section reports inputs required for retorting and upgrading operations at a surface retorting/upgrading facility. Detailed estimates of economics, and of the various manpower,

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. pp. IV-38 to IV-59.

equipment, water, land, and energy requirements are available only for the TOSCO II oil shale process. These estimates are largely based on data reported by the U.S. Bureau of Land Management in the draft Environmental Impact Statement (EIS) for the Colony Development Operation (December 1975) and by Ashland Oil and Shell Oil in the Detailed Development Plan (DDP) for Oil Shale Tract C-b (February 1976).¹ When available, inputs for other surface retorting processes are reported. Data for alternate surface retorting technologies are probably less certain than data reported for the TOSCO II process.

The inputs describe a facility processing 66,000 TPD oil shale. Approximately 50,000 BPD of shale oil products are produced by the plant. The inputs are intended to represent a facility upgrading shale oil to finished fuels or premium feedstocks.

4.5.1.2.a Manpower

Manpower requirements for the full-scale operation of a TOSCO II processing facility are reported in Table 4-63. These requirements include those personnel required for retorting and upgrading operations. The requirements reflect the most recent data available in documents open to the public.² Earlier

¹Ashland Oil and Occidental Oil Shale later rejected the underground mining/TOSCO II retorting scheme and selected Occidental's own modified in-situ process. Shell Oil withdrew from the C-b project.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-10.

TABLE 4-63. MANPOWER REQUIREMENTS FOR 50,000 BPD TOSCO II
SURFACE PROCESSING

Personnel Requirements

Management and Secretarial	26
Technical Services	40
Administrative Support	25
Refinery Supervisor	16
Maintenance Management	31
Plant Operators	108
Plant Maintenance	183
	429

Source: Ashland Oil, Inc. and Shell Oil Company. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976.p. IV-10.

estimates from the Colony EIA and EIS are approximately the same as those tabulated in Table 4-63.^{1,2}

The manpower requirements in Table 4-63 relate only the personnel required for full-scale commercial operations. Accurate estimates of the skill breakdowns for construction personnel required to establish the site are unavailable. However total manpower requirements have been reported by Ashland and Shell and have been shown in Figure 4-7. Peak construction employment is approximately 3300.³

An estimate of cumulative craft labor during all construction phases has been prepared by Ashland and Shell, and is reproduced as Table 4-64. Table 4-64 includes crafts only and does not include staff and staff-support requirements, not the development mine force. In addition, Table 4-64 does not represent the timing of the required crafts.⁴

4.6.1.2b Materials and Equipment

Detailed materials and equipment requirements have not been disclosed by current surface retort developers.

¹Colony Development Operation. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado, Vol. 1. Atlantic Richfield Company (Operator), Denver, Colorado. 1974.

²U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975, p. II-97.

³Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. Figure IV-3.

⁴*Ibid.*, pp. III-2, III-10.

TABLE 4-64. CONSTRUCTION PHASE ESTIMATE OF CRAFT LABOR

Crafts	Man Hour Distribution (%)	Total Craft Man Months
Asbestos	8	5,254
Boilermaker	5	3,284
Bricklayer	1	657
Carpenter	10	6,568
Masons	2	1,314
Electrician	10	6,568
Ironworker	9	5,911
Laborer	18	11,822
Millwright	4	2,627
Operator	5	3,284
Painter	1	657
Pipefitter	20	13,136
Sheetmetal	4	2,627
Teamster	3	1,971
Totals	100	65,680

Source: Ashland Oil, Inc. and Shell Oil Company. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. p. III-10.

The facilities required for surface processing vary with the degree of upgrading performed on site. A complex upgrading crude shale oil to finished fuels or premium feedstocks requires the following process units:

- 1) pyrolysis and oil recovery
- 2) gas recovery and treating
- 3) hydrogen production
- 4) gas-oil hydrogenation
- 5) naphtha hydrogenation
- 6) ammonia separation
- 7) sulfur recovery
- 8) delayed coker
- 9) foul water stripping
- 10) tankage.^{1,2}

Tankage requirements of a 50,000 BPD facility have been reported and are shown in Table 4-65.

The FEA previously prepared a preliminary equipment list for a 100,000 BPD retorting and upgrading facility featuring a U.S.B.M. Gas Combustion Retort. These equipment requirements are shown in Table 4-66. The retort design and upgrading sequence are not current, and are representative of oil shale technology circa 1973.³ The equipment list is presented to illustrate the kinds of equipment required for surface shale processing.

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-39.

²U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975, pp. II-23 to II-47.

³Interagency Task Force on Oil Shale. Potential Future Role of Oil Shale: Prospects and Constraints. Federal Energy Administration. November 1974. pp. A-166, 167, 171.

TABLE 4-65. PRODUCT AND INTERMEDIATE TANKAGE
FOR A 50,000 BPD FACILITY

Tank Service	Storage Capacity *BBL	Tank Description
<u>Plant Site</u>		
Coker Feed	110,000	Cone roof, two tanks @ 55,000 BBL ea.
Gas Oil Hydrotreater Feed	480,000	Cone roof, two tank @ 240,000 BBL ea.
Naphtha Hydrotreater Feed	260,000	Floating roof
Foul Water Stripper Feed	100,000	Cone roof
Gas Oil Hydrotreater Product	155,000	Cone roof
Naphtha Hydrotreater Product	110,000	Floating roof
No. 2 Diesel Fuel	4,000	Cone roof, two tanks 2,300 BBL at mine headframe 1,700 BBL at plant size
Plant Fuel Oil	100	Cone roof
"Butanes" Fuel	3,000	High pressure vessels
Oil-Water Separator Tank	2,000	Cone roof
LPG	4,000	Two high pressure vessels @ 2,000 BBL ea.
Ammonia	2,800	Two NH ₃ vessels @ 1,400 BBL ea.
Sulfur	1,500	Enclosed Pit
<u>Off-Tract Terminal</u>		
LPG	20,000	High pressure vessels eight @ 2,500 BBL ea.
Ammonia	6,600	High pressure vessels three @ 2,200 BBL ea.
Sulfur	20,000 (3,000 long tons)	Cone roof

*The capacities shown are for net contents and do not include allowances for heel or vapor space. These capacities are based on production of 50,000 BPD of shale oil. Higher or lower production rates would modify tank capacities accordingly.

Source: Ashland Oil, Inc. and Shell Oil Company. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. p. IV-61.

TABLE 4-66. DETAILED EQUIPMENT LIST FOR A 100,000 BPD OIL SHALE RETORTING AND UP-GRADING FACILITY

<u>RETORTING PLANT:</u>	
<u>Retort (12 required)</u>	<u>SULFIDE REMOVAL (3 PLANTS (Cont.)):</u>
Size: 56" ID x 20' high retorting section	Centrifuge (9 required)
Type: Bureau of Mines gas combustion retort and Cameron & Jones improved feeding and discharge mechanism	Type: Sharpless super D, stainless
Refractory: 9" firebrick, 9" K-30 insulating brick (retort section)	Hp: 5
Drive: Motor, activated hydraulic	Drive: Motor
Hp: 165 top (feed); 300 bottom (discharge)	
	<u>Condenser (18 required)</u>
<u>Rotoclone (120 required)</u>	Type: Spray
Capacity: 36,000 acfm	Size: 9' ID x 22' high
Drive: Motor	
Hp: 100	<u>DELAYED COKING AND PRIMARY DISTILLATION:</u>
Head developed: 12" water	
	<u>Coke drum (4 required)</u>
<u>Compressor (12 required)</u>	Size: 26' ID x 75' long
(Recycle and product gas)	
Type: Centrifugal	<u>Main fractionator (2 required)</u>
Drive: Motor	Size: 11' ID with 8 plates
Hp: 3,500	
	<u>Oil heating furnace (1 required)</u>
<u>Air compressor (3 required)</u>	Heating capacity: 523,175 Btu/hr
Type: Centrifugal	Tube surface: 70,725 sq ft
Drive: Motor	
Hp: 1,675	<u>Stripper (2 required)</u>
	Size: 6.5' ID with 5 plates
<u>Electrostatic precipitator (48 required)</u>	<u>Absorber (2 required)</u>
Size: 31.25' ID x 15' high	Size: 8' ID with 20 plates
Capacity: 88,000 cfm	
Power: 7.5 kw/hr	<u>Coke cutter (2 required)</u>
	With car and auxiliary coke handling equipment
<u>Shale oil pump to storage (12 required)</u>	
Capacity: 283 gpm	<u>Primary distillation column (2 required)</u>
AP: 20 psi	Size: 20' ID with 5 plates
Hp: 5	
Drive: Motor	<u>Distillation preheat furnace (2 required)</u>
	Heat capacity: 360 million Btu/hr
<u>Retort feed conveyor (3 required)</u>	Tube surface: 48,660 sq ft
Type: Belt	
Size: 54" x 350'	
Drive: Motor	
Hp: 75	

Note: Actual equipment list for more current retorting technologies varies substantially from above list.

Source: Federal Energy Administration, Interagency Task Force on Oil Shale. Project Independence Blueprint, Final Task Force Report, Potential Future Role of Oil Shale Prospects and Constraints, November, 1974, pp. A-166, 167, 171.

Construction material requirements for a 50,000 BPD oil shale facility can be estimated from Bechtel's Energy Supply Planning Model.¹ Materials required during construction include:

Cement	9000 tons
Structural steel	6000 tons
Reinforcing bar	2000 tons
Piping	7000 tons
Valves	2000

These values were extrapolated from Bechtel's data for an 88,000 BPD Petrosix processing plant and may not be accurate.²

4.6.1.2c Economics

Preliminary capital cost estimates for a TOSCO II surface processing plant are shown in Table 4-67. The costs have been reported by Ashland and Shell in the DDP for oil shale tract C-b, and should not be construed as definitive cost estimates. The estimates are based only on preliminary engineering design and project scheduling, and do not include interest during construction and deferred capital expenditures. The capital cost estimates in Table 4-67 include those costs related to the surface processing facilities, and also include costs for general facilities, indirect costs, and working capital. These miscellaneous capital requirements (i.e., costs for general facilities, indirects, and working capital) are attributed to both mining and processing facilities. (Mine capital costs

¹Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco, CA: Bechtel Corporation, 1975.

²The values were scaled from values for an 88,000 BPD Petrosix facility by the following formula:

$$\text{Estimated value} = \text{Bechtel's value} \left(\frac{50,000}{88,000} \right)^{0.6}$$

This scaling method yields only very approximate estimates.

TABLE 4-67. CAPITAL COST ESTIMATES FOR TOSCO II RETORTING AND
UPGRADING FACILITIES^{a, b}

Plant Design and Construction	
Pyrolysis	\$154,000,000
Fractionation and Gas Recovery	21,000,000
Oil Upgrading, By-Product Recovery and Wastewater Treatment	113,000,000
Utilities and General Facilities	77,000,000
Field Costs	96,000,000
Taxes and Insurance	10,000,000
Engineering Services and Fees	78,000,000
Contingency	64,000,000
SUBTOTAL	\$613,000,000
Ceramics, Catalysts, and Chemicals	\$ 13,000,000
Prepaid Process Licenses	7,000,000
Employee Recruitment and Training	10,000,000
Project Management	19,000,000
Miscellaneous Other Costs	19,000,000
Environmental Program and Leasehold Costs	29,000,000
Startup and Fixit Allowance	22,000,000
Working Capital	17,000,000
TOTAL NONMINING/GENERAL	\$750,000,000
 TOTAL CAPITAL	 \$940,000,000^c

^aShale oil production capacity: 50,000 BPD

^bCosts are in 1977 dollars and are indexed from those reported by Ashland and Shell by 1.10.

^cTotal Capital includes capital costs of an underground mine.

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-6, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. p. I-22.

are discussed in Sections 4.5.1.2 and 4.5.2.2.) The costs in Table 4-67 are indexed to 1977 from the October 1975 costs in the DDP. Costs for processed shale disposal are included in mine capital costs (Table 4-21), but are more closely associated with processing activities.¹ Total capital requirements of a 50,000 BPD TOSCO II processing facility and associated underground mine are shown as \$940,000,000.

Preliminary capital costs for a Paraho mining/processing facility producing 100,000 BPD shale oil have been reported as \$1,200,000,000 (1976 dollars).² The Paraho upgrading sequence produces a crude shale oil requiring additional refining, and thus avoids some of the upgrading costs that have been reported for the TOSCO II process.

Operating cost estimates have not been disclosed by current oil shale developers. However, data reported in the DDP and EIS are sufficient to construct preliminary cost estimates. These estimates are shown in Table 4-68, and are based on preliminary, incomplete data.^{3,4} The labor costs are estimated from the labor requirements reported by Ashland and Shell in the DDP. Utility costs are estimated from the power requirements reported in the EIS. All other costs are estimated as percentages of the capital or labor costs.

¹Ashland Oil, Inc., and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. I-22.

²West, J. "Obstacles to Limit U.S. Shale Production", Oil and Gas Journal 75 (35): 523-525, August 1977.

³Ashland Oil, Inc. and Shell Oil Co., *op.cit.*

⁴U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975.

TABLE 4-68. ANNUALIZED OPERATING COSTS FOR A 50,000 BPD
TOSCO II PROCESSING FACILITY^a

Direct Costs		
Management and Secretarial	\$ 320,000 ^b	
Technical Services	800,000 ^b	
Administrative Support	500,000 ^b	
Refinery Supervisor	320,000 ^b	
Maintenance Management	620,000 ^b	
Plant Operators	1,600,000 ^c	
Plant Maintenance	2,700,000 ^c	
Total Personnel Costs	\$ 7,100,000	
Operating Supplies	6,100,000 ^d	
Maintenance Materials	3,300,000 ^e	
Utilities		
Electricity	27,000,000 ^f	
Water ^g	—	
Surface Fuel ^h	—	
Fixed Costs		
Depreciation	61,000,000 ⁱ	
Taxes and Insurance	18,000,000 ^j	
Plant Overhead	3,500,000 ^k	
TOTAL	\$126,000,000	\$6.90/bbl

^aCosts are in 1977 dollars and include only those costs directly attributed to the retorting/processing.

^bCalculated @ \$20,000/man/year.

^cCalculated @ \$15,000/man year.

^dCalculated @ 1% of the fixed capital costs.

^eCalculated @ 100% of maintenance labor.

^fCalculated @ \$0.04/kwh.

^gWater costs have not been specified and are probably not significant. Power costs include costs for water treatment.

^hSurface fuel requirements are met by fuel produced during upgrading.

ⁱCalculated @ 10% of fixed capital.

^jCalculated @ 3% of fixed capital.

^kCalculated @ 50% of total labor costs.

Note: Rates for calculating fixed costs, plant overhead, and costs for operating supplies and maintenance materials are largely based on Peters, M. S. and K. D. Timmerhaus. Plant Design and Economics for Chemical Engineers, 2nd. Ed. (New York: McGraw-Hill Book Co., 1968), pp. 132-141.

Source: U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado. Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975.

Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume 1, Prepared for Area Oil Shale Supervisor. February 1976.

4.6.1.2d Water

A TOSCO II processing facility requires water for mining; crushing and conveying; coarse-ore storage; retorting and upgrading; processed shale disposal; and general plant and personnel use. Figure 4-26 reports the water system flow for a 50,000 BPD TOSCO II processing facility.

Consumptive uses of water during retorting, upgrading, and shale disposal are summarized in Table 4-69. Net water requirements of TOSCO II processing are shown as 5030 gpm (8100 acre-ft/year) for a shale oil production of 50,000 BPD. Water requirements for mining, crushing, conveying, and coarse-ore storage are discussed in Sections 4.5.1.2 and 4.5.2.2. Revegetation water requirements are discussed in Section 4.7.

A major use of water is the moisturization of processed shale. All waste water streams not otherwise recycled are used for shale moisturization. Water used for moisturizing processed shale or for dust control on the processed shale embankment will either evaporate, be incorporated into the wastepile, or drain into a catchment basin for recycle. Other uses include steam generation in the reforming process to produce hydrogen for the hydrotreating units, use as potable water, and evaporation losses from the cooling tower and the pyrolysis unit.¹

Water uses during construction include concrete manufacture, dust control, fill compaction, and personnel uses. Quantities for these uses amount to 500-700 gpm.² The entire requirement can probably be met by water from mine dewatering operations.

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. p. IV-62.

²*Ibid.*

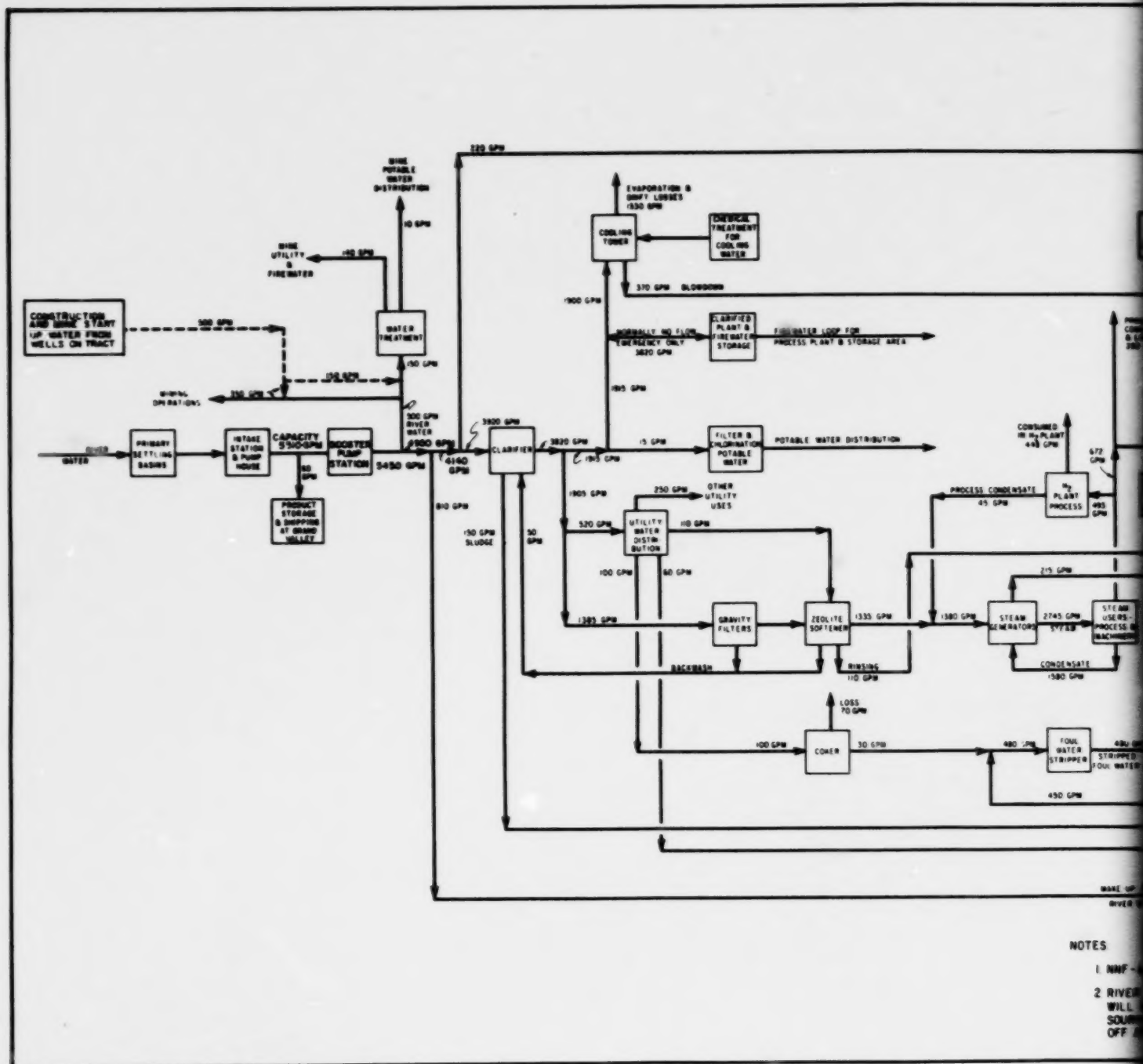


Figure 4-26. Water System Flow Diagram of TOSO

Source: Ashland Oil, Inc. and Shell Oil Company. Detailed Development of the TOSO Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor

TABLE 4-69. USES OF WATER BY TOSCO II SHALE PROCESS PRODUCING
50,000 BPD SHALE OIL^a

Use	Quantity
Cooling Tower: Evaporation and Drift	1530 gpm
Hydrogen Plant	448 gpm
Steam Users and Loss	282 gpm
Coker	70 gpm
Evaporation from Pyrolysis Unit	1620 gpm
Shale Moisturization	1500 gpm
Utility	250 gpm
Potable Water	<u>15 gpm</u>
TOTAL GROSS CONSUMPTION	5720 gpm
Water Entering System with Raw Shale or Co-produced with Shale Oil	<u>685 gpm</u>
NET CONSUMPTIVE WATER USE	5030 gpm

^aDoes not include mine consumption, crusher/ore storage uses,
or revegetation

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Develop-
ment Plan and Related Materials for Oil Shale Supervisor.
February 1976. p. IV-63.

McKee and Kunchal have examined the water requirements for a full-scale Paraho oil shale plant operating with direct or indirect heating. Their data are summarized in Table 4-70, as linearly scaled to a facility producing 50,000 BPD shale oil. Indirect heating consumes about 33% more water than direct heating, due to increased revegetation water needs. The consumption values in Table 4-70 are not comparable to those in Table 4-69 for TOSCO II processing due to differing upgrading schemes.¹

Total water requirements for the Union Retort B process producing 50,000 BPD shale oil are approximately 2600 gpm. Included are requirements for retorting, cooling, gas treatment, deasher, scrubber, processed shale moisturizing and disposal. The reported requirement does not include any water requirements for upgrading.²

The total water consumption for a Lurgi-Ruhrgas process producing 50,000 BPD shale oil has been estimated as 1470 gpm. Water requirements for gas recovery and treatment, and for shale oil upgrading are not included in the reported value.³

The net consumption of water for a Superior process producing 10,000-15,000 BPD shale oil is reported to be 880 gpm. This amounts to a net requirement of 3500 gpm for a facility

¹McKee, J. M., and E. K. Kunchal. "Energy and Water Requirements for an Oil Shale Plant Based on the Paraho Process", 9th Oil Shale Symposium, Colorado School of Mines, April 29, 1976.

²Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-02-3535. Austin, TX: Radian Corporation, September 1977. p. 76.

³"Development of the Lurgi-Ruhrgas Retort for the Distillation of Oil Shale", Lurgi Mineralotechniek GMBH, October 1973.

TABLE 4-70. WATER REQUIREMENTS OF A 50,000 BPD PARAHO SHALE OIL PLANT^{a,b}

Use	Water Requirements (gpm)	
	Direct Mode	Indirect Mode
Evaporation from cooling tower	1990	1990
Pre-refining and power generation	220	220
Retorting (dust control)	50	50
Revegetation ^c	<u>870</u> 3130	<u>1890</u> 4150

^aBasis: 30 gal/ton oil shale.

^bDoes not include water requirements of mining and crushing.

^cMore akin to moisturization rather than revegetation. This requirement varies for each mode of operation due to varying processed shale compositions.

Source: McKee, J.M., and E.K. Kunchal, "Energy and Water Requirements for an Oil Shale Plant Based on the Paraho Process." 9th Oil Shale Symposium, Colorado School of Mines, April 29, 1976.

producing 40,000-60,000 BPD. All water requirements can probably be satisfied with saline water from a "leached" zone aquifer.¹

4.6.1.2e Land

Ashland and Shell have projected surface disturbances associated with a TOSCO II processing facility. Estimates of the acreage disturbed by a 50,000 BPD facility are reported in Table 4-71. The largest disturbance is associated with the disposal of processed shale. Ashland and Shell expected a processed shale pile to eventually cover 1000-1200 acres on the tract. Backfilling the mine with processed shale could reduce the amount of processed shale disposed of on the surface. It has been estimated that backfilling can begin within 5-10 years after the start of production.²

4.6.1.2f Ancillary Energy

Energy requirements of a TOSCO II processing facility include:

- 1) gas, liquid, and diesel fuels
- 2) steam
- 3) electric power.

¹Prien, C. H. "Superior Oil Shale Process", Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. pp. V-96, V-110.

TABLE 4-71. SURFACE AREAS DISTURBED BY A TOSCO II PROCESS
PRODUCING 50,000 BPD SHALE OIL

Disturbance	Area Disturbed (Acres)
Truck Maintenance Facility	10-15
Plant Site	150-200
Processed Shale Handling System	15-20
Power R-O-W	5-15
Pipeline Corridor R-O-W	10-20
Auxiliary Buildings	28-35
Processed Shale Disposal	1000-1200

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Trace c-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p IV-9.

The TOSCO II processing complex is self-sufficient in gas and liquid fuels after it commences operations. During initial start-up, purchased fuel oil is burned. Three fuels are used in the plant: a treated fuel gas, a treated liquid mixture of butanes and butenes, and a distillate fuel oil. All of the fuel gas and butane-butene liquid mixture produced in the plant are consumed internally. The fuel oil can be gas oil or a blend of gas oil and naphtha. Fuel gas is used as a feed gas in the production of hydrogen. Heat loads to the various processing units are summarized in Table 4-72. These energy demands are not ancillary energy requirements; since the demands can be met by fuels produced in the process.¹

Diesel fuel produced in the gas-oil hydrogenation unit can be used in mine and processed-shale disposal operations. Approximately 17,000-21,000 gallons of diesel fuel are required each day for these operations at a complex producing 50,000 BPD. Once again, these energy demands are not ancillary energy requirements.²

Most of the plant requirements for steam are met by using process waste-heat boilers.³

The required electric load for a TOSCO II processing facility producing 50,000 BPD amounts to about 100,000 KVA, with an estimated operating load of about 80,000 KVA.⁴ This energy demand

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-63.

²*Ibid.*

³*Ibid.*

⁴*Ibid.*

TABLE 4-72. HEAT LOADS TO PROCESSING UNITS AT A TOSCO II
FACILITY PRODUCING 50,000 BPD^{a,b}

Processing Unit	Firing Duty (MM Btu/hr)
Pyrolysis and Oil Recovery	
Preheat System	2046
Steam Superheater	126
Hydrogen Production	604
Gas Oil Hydrogenation	
Reactor Feed Heater	20
Fired Reboiler	63
Naphtha Hydrogenation	7
Utility Boilers	200
Delayed Coker	88
Sulfur Recovery	10

^aThese heat loads are not ancillary energy requirements since the demands can be met by fuels produced in the process.

^bHeat loads for delayed coking are those reported in the Colony Development Operation EIA; all other duties are those reported in the Bureau of Land Management's EIS.

Sources: U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C. December, 1975. pp. II-28 to II-45.

Colony Development Operation. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado. Vol. I. Atlantic Pichfield Company (Operator), Denver, Colorado, 1974. p. 201.

properly represents ancillary energy requirements, and is equal to an energy consumption of 7×10^8 kwh/year. The energy recovery ratio for TOSCO II retorting/processing is determined to be 0.62. This energy recovery ratio is defined as the ratio of the heating value of all products to the heating value of all inputs. The heating value of the products includes the net liquid and gas fuels produced along with the coke produced. Sulfur and ammonia are not included. The input heating value includes the gross heating value of the raw shale and the ancillary electrical inputs.

Power demands for a Union Retort B process are similar to those reported for a TOSCO II process. Power requirements for a 50,000 BPD complex amount to 70,000 kw.¹ This figure represents a yearly consumption of about 6×10^8 kwh.

Energy requirements for the Paraho process are scaled from those reported for a 100,000 BPD facility. These requirements amount to 36 megawatts for retorting and 15 megawatts for pre-refining. In the direct mode, potentially 200 megawatts of electrical power can be exported for sale. Only 40 megawatts are available for export if the retort is operated in the indirect mode.²

The power requirement for a Lurgi-Ruhrgas producing 50,000 BPD shale oil has been reported as 29,000 kw.³ This amounts to a yearly consumption of about 3×10^8 kwh. Power demands of gas recovery and treating and shale oil upgrading are not included in this estimate.

¹Shih, C. C. "Union Oil Shale Retorting Process", Technological Overview Reports for Eight Oil Shale Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976.

²McKee, J. M., and E. K. Kunchal. "Energy and Water Requirements for an Oil Shale Plant Based on the Paraho Process:", 9th Oil Shale Symposium, Colorado School of Mines, April 29, 1976.

³"Development of the Lurgi-Ruhrgas Retort for the Distillation of Oil Shale." Lurgi Mineraloltechnik GMBH, October 1973

4.6.1.3 Outputs

This section reports the various outputs associated with the operation of a surface processing facility producing 50,000 BPD. Discussions of air emissions, water effluents, solid wastes, noise pollution, occupational health and safety, and odor are largely based on information reported by developers of the TOSCO II process in a published development plan and in an environmental impact statement.^{1,2} These emission estimates do not necessarily represent those achievable with best available control technology (BACT). Outputs reported for other surface retorting processes are based on more preliminary engineering designs.

The data reported below assume the upgrading of crude shale oil to finished fuels or premium refinery feedstocks.

4.6.1.3a Air Emissions

Air emissions from surface retorting/processing operations originate from: retorting and upgrading operations, shale oil storage, steam generation, processed-shale disposal, and wastewater treatment. Emissions from these sources are described below. Quantitative estimates are not available for emissions from wastewater treatment.

A summary of the estimated ranges of emissions from retorting and upgrading operations, steam generation, and shale oil storage is presented in Table 4-73. The summary represents the

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976.

²U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975.

TABLE 4-73. SUMMARY OF AIR EMISSIONS FROM A TOSCO II PROCESSING FACILITY PRODUCING 50,000 BPD SHALE OIL PRODUCTS

Source	Estimated Normal Emissions (lb/hr)					Stack Parameters						
	Particulates	Sulfur Dioxide	Total Hydrocarbons	Carbon Monoxide	Nitrogen Oxides	Carbon Dioxide ^a	Stack Height	Stack Exit Diameter	Total Stack Gases	Molecular Weight	Exit Temperature	Moisture Content
1. Pyrolysis and Oil Recovery Unit												
A. Preheat System (6 units)	250-300 ^b	10-60	250-300	40-50	1400-1600	120,000	310 ft	9.3 ft	1,272,000 acfm	27.2	127°F	Saturated
B. Steam Superheater-Ball Circulation System (6 units)	200-250	80-120	<1	<5	110-130	20,000	310 ft	4.5 ft	265,800 acfm	26	146°F	Saturated
C. Processed Shale Moisturing Systems (6 units)	250-300	0	0	0	0	0	310 ft	4.5 ft	266,400 acfm	20.2	184°F	Steam
2. Hydrogen Unit (4 furnaces)	10-15	25-35	3	10-15	80-110	95,000	80 ft	5.7 ft	296,420 acfm	28	440°F	Combustion Products
3. Gas Oil Hydrogenation Unit												
A. Reactor Heaters (2 units)	<1	<1	<1	<1	<5	3,000	75 ft	2.5 ft	21,000 acfm	28.1	900°F	Combustion Products
B. Reboiler Heater	<3	<5	<1	<1	10-15	10,000	150 ft	5.7 ft	53,000 acfm	28.1	700°F	Combustion Products
4. Naptha Hydrogenation Unit	<1	<1	<1	<1	<3	1,000	75 ft	2.5 ft	5,250 acfm	28.1	800°F	Combustion Products
5. Delayed Coker Unit	<2	<5	<1	<1	5-10	14,000	175 ft	7.5 ft	42,000 acfm	28	350°F	Combustion Products
6. Utility Boilers (2 units)	<5	10-15	<5	<5	20-30	12,000	55 ft	7 ft	52,000 acfm	28	400°F	Combustion Products
7. Sulfur Recovery Unit	NIL	90-110	NIL	NIL	NIL	0,000	210 ft	8 ft	129,800 acfm	31.1	125°F	Saturated
8. Miscellaneous Refining			680				5 ft					
9. Storage			24				50 ft					

^aCarbon dioxide emissions are estimated by assuming complete combustion of carbon in fuels to CO₂; calculations from sulfur recovery unit include estimate of CO₂ produced from decomposition of dolomite.

^bIncludes condensable HC.

Sources: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor, February 1976. P. V-7.

U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado. Draft Environmental Impact Statement. HES-73-62. Washington, D.C. December 1975. pp. 11-28 to 11-49.

Nadian Corporation. A Western Regional Energy Development Study. Final Report. August 1975.

most recent presentation of TOSCO II emissions as reported in the DDP for oil shale trace C-b.¹ Emissions reported in the EIS for the Colony Development Operation² are essentially similar to those reported in the DDP. These emissions agree reasonably well with EPA emissions factors for combustion sources. Specific air contaminants are discussed below.

Sulfur dioxide is emitted from combustion processes and from the tail-gas unit in the sulfur recovery plant. Hydrogen sulfide is present in retort gases and is thus a potential contaminant from process spills and leaks. However, most of the H₂S in fuel gas and plant fuel oil is oxidized to sulfur dioxide in various process burners. Sulfur dioxide emissions from diesel trucks required for processed shale disposal are negligible.³ Estimated SO₂ emissions from the plant combustion sources are based on the sulfur contents of the plant fuel gas and fuel oil, and on the observed emissions from 25 TPD and 1000 TPD pilot and semi-works plant operations.⁴ A Claus plant recovers about 95% of the sulfur in the acid gas feed to the sulfur recovery unit. The tail gas stream from the Claus plant contains approximately 5% of the original sulfur and is routed to a tail gas treating unit. Performances of tail gas treating units vary; however, approximately 95% of the remaining sulfur should be removed.⁵

¹Ashland Oil, Inc. and Shell Oil Co., *op.cit.*, p. V-7.

²U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975. pp. II-28 to II-49.

³Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for the U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, TX: Radian Corporation, September 1977.

⁴Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. pp. V-6 to V-8.

⁵Colley, J. D., W. A. Gathman, and M. L. Owen, *op.cit.*, p. 33.

Solid particulates are emitted from raw-shale preheating, processed-shale moisturization, ball-circulation system operations, processed-shale disposal and processed-shale piles. According to Colorado regulations, condensible hydrocarbons are considered particulates. Particulate emissions in Table 4-73 are based on EPA emission factors for gas, butane, and distillate oil combustion.¹ During occasional soot blowing, boiler "lancing", and fuel switching, additional particulates may be released.

Venturi wet scrubbers remove 95.8 to 99.8 percent of the shale dust from the preheat and ball circulation systems. Wet scrubbers remove about 93% of the processed shale dust from the shale moisturizer.²

Particles emitted from the plant contain the same elements and compounds found in retorted shale. Analyses of the elemental concentrations in TOSCO II-retorted shale are shown in Table 4-74. These concentrations depend on the composition of raw shale being retorted. The mineral constituents of several surface retorted shales are shown in Table 4-75.

Polycyclic aromatic hydrocarbons are also found in particulate emissions from the processing plant. Those PAH detected in TOSCO II surface-retorted shale are reported in Table 4-76. All of the compounds in Table 4-76 are known or suspected

¹Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. 2nd Ed. AP-42. Research Triangle Park, NC: 1973.

²Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, TX: Radian Corporation, September 1977. pp. 53-54.

TABLE 4-74. ELEMENTAL CONCENTRATIONS IN TOSCO II
SURFACE-RETORTED OIL SHALE

Element	Concentration (wt. ppm)	Element	Concentration (wt. ppm)	Element	Concentration (wt. ppm)
Li	850	Zr	9.3	Gd	0.40
Be	35	Nb	3.4	Tb	0.07
B	140	Mo	4.9	Dy	0.40
F	1,700	Ru	<0.1	Ho	0.07
Cl	72	Rh	<0.1	Er	0.27
Sc	2.4	Pd	<0.1	Yb	0.25
Ti	570	Ag	<0.01	Lu	<0.1
V	29	Cd	0.14	Hf	<0.1
Cr	49	In	Standard	Ta	0.04
Mn	34	Sn	0.11	W	0.42
Co	39	Sb	0.39	Re	<0.1
Ni	11	Te	<0.1	Os	<0.1
Cu	15	I	<0.01	Ir	<0.1
Zn	13	Cs	1.2	Pt	<0.1
Ga	2.2	Ba	32	Au	<0.1
Ge	0.40	La	1.4	Hg	<0.1
As	7.2	Ce	1.6	Tl	0.14
Se	0.08	Pr	0.25	Pb	10
Br	0.01	Nd	1.2	Bi	0.36
Rb	29	Sm	0.44	Th	0.77
Sr	69	Eu	0.12	U	0.99
Y	1.2				

Source: Colony Development Operation. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado, Volume I. Atlantic Richfield Company (Operator), Denver, Colorado. 1974. p. 208.

TABLE 4-75. MINERAL CONSTITUENTS IN TYPICAL RETORTED OIL SHALES

Component	TOSCO II ^a wt %	Union B ^b wt %	USBM ^c wt%
SiO ₂	33.0	31.5	43.8
Fe ₂ O ₃	2.5	2.8	4.6
Al ₂ O ₃	6.8	6.9	12.2
CaO	15.8	19.6	22.1
MgO	5.3	5.7	9.3
SO ₃	-	1.9	2.2
Na ₂ O	8.7	2.2	3.4
K ₂ O	3.3	1.6	2.4

^aColony Environmental Impact Analysis, 1974. Data represent Mahogany zone shale (~35 gal/ton) from Parachute Creek area.

^bLipman, S.C., Union Oil Co. Revegetation Studies. Data represent Mahogany zone shale (~35 gal/ton) from Parachute Creek area.

^cStanfield, et.al., Data represent Mahogany zone shale (~30 gal/ton) from Anvil Points.

Sources: Colony Development Operation. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado, Vol. I. Atlantic Richfield Company (Operator), Denver, CO. 1974. p. 207.

Lipman, S.C. "Union Oil Company Revegetation Studies." Environmental Oil Shale Symposium. Colorado School of Mines, October 9-10, 1975.

Stanfield, K.W., et. al. "Properties of Colorado Oil Shale." USBM, Report of Investigations No, 4825, 1951.

TABLE 4-76. POLYCYCLIC AROMATIC HYDROCARBONS DETECTED IN
TOSCO II SURFACE-RETORTED SHALE

Benzo(a)pyrene (BaP)	Fluoranthene
Alkyl I (BaP)	Benz(a)anthracene
Alkyl II (BaP)	Triphenylene
Benzo(ghi)fluoranthene	Phenanthrene
Benzo(e)pyrene	7,12-Dimethylbenz(a)anthracene
Perylene	3-Methylcholanthrene
Benzo(ghi)perylene	Coronene
Anthanthrene	Chrysene
Pyrene	

Source: Coomes, R.M. "Health Effects of Oil Shale Processing."
Quarterly of the Colorado School of Mines 71(4):
101-123, October 1976.

animal carcinogens and may be carcinogenic to man. Concentrations of these compounds have not been reported.

Using an emission factor reported by PEDCo-Environmental, fugitive dust emissions from the processed shale pile are estimated as 1.6 tons/acre/year, assuming 80% dust control by a chemical stabilizer.¹ If 160 acres are disturbed each year, dust emissions amount to about 60 lbs/hr. Emissions during transport of the processed shale have not been estimated. Coke cutting, dumping, and loading are other potential sources of fugitive dust.²

Hydrocarbons at concentrations of about 90 ppm are contained in flue gases from the retort preheat systems. About half of the hydrocarbons are condensible at exhaust conditions and are therefore classed as particulates. Minor quantities of hydrocarbons are produced in all combustion operations. Diesel equipment operated during processed shale disposal emits unburned hydrocarbons, aldehydes, organic acids, and smoke. Under upset conditions, if retorting is incomplete because of insufficient temperatures or residence time, the resulting processed shale may emit hydrocarbons. However, these conditions occur infrequently.³

The following assumptions based on literature, data, and experience are formulated to calculate the hydrocarbon emissions from petroleum storage:

¹Cowherd, Charlten, Jr., et al. Development of Emission Factors for Fugitive Dust Sources, Final Report. EPA-450/3-74-037, Contract No. 68-02-0619. Kansas City, Mo.: Midwest Research Institute, June 1974.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. pp. V-8 to V-9.

³*Ibid.*

- 1) All product storage is in floating roof tanks.
- 2) Storage capacity is 10 days' production.¹
- 3) Combined hydrocarbon product is equivalent to crude oil.

Using petroleum storage emission factors for storing crude oil in floating roof tanks, hydrocarbon emissions from storage are calculated to be 24 lb/hr. Floating roof tanks provide approximately 90-95% control of hydrocarbon emissions from storage.²

There are numerous hydrocarbon emissions in the shale oil upgrading facilities from sources such as valve stems, flanges, loading racks, equipment leaks, pump seals, sumps, and API separators. These losses are discussed in Radian Corporation's Refinery Siting Report.³ Based on literature data, Radian found that the miscellaneous hydrocarbon emissions amount to about 0.1 wt % of refinery capacity for a new well-designed, well-maintained refinery. This value of 0.1 wt % is used to determine miscellaneous emissions from the shale oil up-grading facilities. Upgrading capacity is considered to be the feed to the distillation tower (50,000 bbl/day). Hydrocarbon emissions from miscellaneous sources are calculated to be 680 lb/hr. The composition of these hydrocarbons can be expected to be a composite of all

¹Hittman Associates, Inc. Environmental Impacts, Efficiency and Cost of Energy Supplied by Emerging Technologies, Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Columbia, MD: May 1974.

²Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. 2nd Ed. AP-42. Research Triangle Park, NC: 1973.

³Radian Corporation. A Program to Investigate Various Factors in Refinery Siting. Prepared for Council on Environmental Quality and U.S. Environmental Protection Agency. Austin, TX: 1974.

volatile intermediate and refined products. The emissions are assumed to occur at an average height of 5 feet.^{1,2}

Estimates of plant carbon monoxide emissions are based on EPA emission factors for gas, butane, and distillate oil combustion.³ Emissions of carbon monoxide from diesel equipment used in processed shale disposal have not been estimated.

Evaporation and holding ponds are possible sources of the volatile compounds found in the various wastewaters. Atmospheric emissions from ponds have not been characterized but are likely to contain ammonia and hydrogen sulfide.⁴ Hydrocarbon emissions from ponds are included in miscellaneous hydrocarbon emissions.

Since the complex produces ammonia as a by-product, ammonia may be released to the atmosphere from spills and leaks.

Temperatures and redox conditions during retorting are not severe enough to volatilize most metallic elements. With notable exceptions such as arsenic, selenium, and antimony, most trace elements remain with the processed shale or are found in shale solids entrained in retort gases.⁵

¹Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, TX: Radian Corporation, September 1977. p. 55.

²Radian Corporation. A Program to Investigate Various Factors in Refinery Siting. Prepared for Council on Environmental Quality and U.S. Environmental Protection Agency. Austin, TX: 1974.

³Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. 2nd Ed. AP-42. Research Triangle Park, NC: 1973.

⁴Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 74.

⁵*Ibid.*, p. 67.

Air emissions for pyrolysis and oil recovery units of Paraho and Union Retort B processes are summarized in Table 4-77.

4.6.1.3b Water Effluents

Direct wastewater discharge from a TOSCO II retorting and upgrading operation is not anticipated. All wastewater is re-used in plant operations and ultimately consumed in moisturizing processed shale.^{1,2,3}

Plant process wastewaters are collected, processed to reclaim useful components, and combined for in-plant treatment before re-use. Major sources of wastewater are:

- 1) pyrolysis and oil recovery units - blowdown water that is produced from the venturi scrubbers used to remove shale dust from flue gas;
- 2) gas oil and naphtha hydrogenation units - sour water that is produced by the washing operation;
- 3) ammonia separation and sulfur recovery units - ammonia-stripped water and an acidic wastewater;

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 81.

²Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976.

³U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975.

⁴Crawford, K. W., et al., *op.cit.*

TABLE 4-77. AIR EMISSIONS FROM THE PARAHO
AND UNION B RETORTS^{a,b}

	Paraho	Union B
Particulates	91 lb/hr	63 lb/hr
SO ₂	114 lb/hr	140 lb/hr
Total Organics	24 lb/hr	30 lb/hr
CO	39 lb/hr	66 lb/hr
NO _x	1140 lb/hr	622 lb/hr
Rate	1,300,000 scfm	-

^aData describe emissions from the pyrolysis and oil recovery unit only.

^bBased on production of 50,000 BPD.

Source: Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-01-3535. Austin, TX: Radian Corporation, September 1977. pp. 65, 78.

- 4) delayed coker units - foul water;
- 5) utilities - boiler and cooling water blowdowns;
- 6) Wellman-Lord unit - blowdown of alkaline sulfate/sulfite wastewaters.¹

The composition of the combined process wastewater stream is shown in Table 4-78. Major constituents in the combined process water are organic acids, neutral oils, amines and phenols, and mineral salts such as sodium, calcium, and magnesium sulfates, chlorides, and carbonates. High molecular weight polycyclic organics may also be present. Twenty-two trace elements have also been identified in combined wastewater; none of these is present in quantities greater than 1 mg/l.

Table 4-79 is a summary of the major constituents present in Paraho retort wastewater. Because of the significant amounts of organic materials present in the wastewater, the biochemical oxygen demand (BOD) and chemical oxygen demand (COD) are high. The data in Table 4-79 include no downstream upgrading operations.²

The major wastewater streams from Union Oil's retorting process are:

- 1) water from gas compression and cooling,
- 2) water from ammonia absorption,

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 81.

²*Ibid.*, p. 83.

TABLE 4-78. APPROXIMATE COMPOSITION OF TOSCO II COMBINED
PROCESS WASTEWATER (50,000 BPD UPGRADED SHALE
OIL PRODUCTION)

Component	Concentration in Water (ppm) Added to Spent Shale	lb/hr
Ca ⁺²	280	190
Mg ⁺²	100	70
Na ⁺¹	670	450
NH ₄ ⁺¹	16	10
Zn ⁺²	5	4
As ⁺⁵	.015 - 0.3	0.01 - 0.2
Cr ⁺⁶	2	1
CO ₃ ⁻²	360	240
HCO ₃ ⁻¹	100	70
SO ₄ ⁻²	850	575
S ₂ O ₃ ⁻²	90	60
PO ₄ ⁻³	5	4
Cl ⁻¹	570	385
CN ⁻¹	5	4
Phenols	315	215
Amines	410	280
Organic Acids	1,330	900
Neutral Oils	960	650
Chelate	5	4
TOTALS (Rounded)	6,100	1,870

In addition to above, elements present in trace quantities (less than 1 ppm) are Pb, Ce, Ag, Mo, Zr, Sr, Rb, Br, Se, Cu, Ni, Co, Fe, Mn, V, Ti, K, P, Al, F, B, Li.

Source: U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C. December 1975. p. II-29

TABLE 4-79. ANALYSIS OF PARAHO PROCESS WASTEWATER

Concentration (mg/l)	
<u>Constituents</u>	
Ammonia nitrogen	2,000 - 20,000
Organic carbon	10,000 - 29,000
Organic nitrogen	4,000 - 12,000
Carbonates	2,000 - 24,000
Bicarbonates	5,000 - 26,000
<u>Parameters</u>	
BOD	5,000 - 12,000
COD	17,000 - 20,000

Sources: Hendrickson, T. A., comp. Synthetic Fuels Data Handbook. Denver, CO: Cameron Engineers, Inc. 1975.

Jones, J. B. "The Paraho Oil Shale Retort." 9th Oil Shale Symposium, Colorado School of Mines. Golden, Colorado. April 29-30, 1976.

Data collected by TRW/DRI during sampling at Paraho facility. Anvil Points, Colorado. March 1976.

- 3) water from oil-water separator,
- 4) water from first stage solids removal, and
- 5) water from oil stripper condensate drum.

These wastewaters are combined, stored, and re-used for processed shale cooling and some water stripping. Little data has been disclosed on the composition and quantities of these waste streams.¹

Wastewater treatment systems are generally similar to those employed at oil refineries, and are summarized in Chapter 6, Crude Oil Resource Development System.²

Runoff water from processed shale will contain higher concentrations of dissolved solids than runoff waters from undisturbed areas. Laboratory and field experiments have shown that sodium, calcium, magnesium, potassium, bicarbonate, sulfate, and chloride are present in waters contacted with freshly processed shale. Table 4-80 presents results of laboratory experiments on raw and retorted shales. TOSCO II and USBM retorted shales contain about 20 lb/ton of readily leachable salts, roughly 4 times that from raw shale. The total soluble salts depend heavily on the extent of carbon combustion and mineral decomposition that occur in the combustion zone of a gas combustion retort.³ Other compounds and elements potentially leachable from processed shale are shown in Tables 4-74 and 4-76.

¹Crawford, K. W. et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 83.

²*Ibid.*, pp. 84, 86.

³*Ibid.*, pp. 90, 91.

TABLE 4-80. INORGANIC IONS LEACHABLE FROM FRESHLY RETORTED SHALES (lb/ton)

Ion	Raw Shale	TOSCO II-Retorted Shale	USBM-Retorted Shale	Union A-Retorted Shale
K ⁺	0.48	0.64	1.44	12.5
Na ⁺	0.96	3.30	4.50	42.0
Ca ⁺⁺	0.2	2.30	0.84	6.54
Mg ⁺⁺	0.02	0.54	0.08	1.82
HCO ₃ ⁻	1.50	0.40	0.76	0.56
Cl ⁻	0.44	0.16	0.26	0.66
SO ₄ ⁼	1.58	14.6	12.0	124.6
Total	5.18	22	20	188
(lb ions/ton shale)				

Source: Ward, J. E., et. al. "Water Pollution Potential of Rainfall on Spent Shale Residues." Colorado State University. Prepared for U.S. EPA under Grant #14030 EDB. December 1971. As cited in: Crawford, K. W., et. al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. p. 91.

Potential shale developers plan to collect shale pile runoff water in catchment ponds. The developers of tract C-b planned an impoundment sufficient to withstand a 100-year flood. Water collected in the pond can be re-cycled to the shale processing plant.¹ Groundwater is also potentially contaminated by leachate from the processed shale pile.

4.6.1.3c Solid Wastes

Solid wastes associated with a 50,000 BPD TOSCO II processing facility are tabulated in Table 4-81. Table 4-81 is based on data reported in the EIS for the Colony Development Operation. Data reported in the DDP for oil shale tract C-b are generally similar to those reported in Table 4-81.

One of the major environmental problems associated with oil shale development is the disposal of large quantities of processed shale. A facility producing 50,000 BPD shale oil from shale containing 30 gal/ton must dispose of over 53,000 tons of processed shale per day.² This shale contains toxic elements, metals, and organic compounds that can be leached from the shale (See Tables 4-74 through 4-76). Potential backfilling of surface and underground mines is no panacea: toxic substances within the shale may be leached by underground water. Backfilling of an underground mine can begin only after 5-10 years of operation.³ Backfilling of surface mines may not be feasible for

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. pp. V-47,48.

²U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975, p. II-48.

³Ashland Oil, Inc. and Shell Oil Co., *op.cit.*, p. V-110.

TABLE 4-81. MAJOR SOLID WASTES FROM A TOSCO II COMPLEX
PRODUCING 50,000 BPD

Source of Solid Waste	Approximate Quantity	Annual Production	Major Constituent
<u>Pyrolysis Unit</u>			
Processed Shale	53,200 T/D*	19,418,000 T	Processed Shale
Clarifier Sludge from Set Scrubbers- Preheat System	860 T/D*	313,900 T	Raw Shale Dust
Ball Circulation System	65 T/D*	23,725 T	Processed Shale Dust
Processed Shale Moisturizing System	43 T/D*	15,695 T	Processed Shale Dust
Total	54,168 T/D		
<u>Upgrading Units (Hydrotreaters)</u>			
Naphtha	0- 75 T/2 yrs (max)	0- 75 T	Spent HDN Catalyst
Naphtha	60 T/yr	60 T	Proprietary Solid
Gas Oil	0-260 T/yr (max)	0-130 T	Spent HDN Catalyst
Gas Oil	350-475 T/yr	350-475 T	Proprietary Solid
<u>Hydrogen Unit</u>			
Hydrodesulfurizer	135 T/3-5 yrs	34 T	Spent HDS Catalyst
Caustic Wash	2.4 T/D	876 T	Spent Aqueous Caustic
Guard Bed	15 T/1-3 yrs	7 T	Spent ZnS Catalyst
Shift Converter (High Temp.)	50 T/5 yrs	10 T	Spent Fe-Cr Catalyst
Shift Converter (Low Temp.)	50 T/3 yrs	16 T	Spent Cu-Zn Catalyst
<u>Sulfur Unit</u>			
Claus Unit	150 T/2 yrs	75 T	Spent Bauxite Catalyst
Tail Gas Hydrotreater	10 T/5 yrs	2 T	Spent Co, Ni-Mo Catalyst
<u>Gas Treating Unit</u>			
DEA Filter	8.25 T/2 weeks	429 T	Diatomaceous Earth
DEA Filter	8.25 T/2 weeks	429 T	Deactivated Carbon
<u>Coker Unit</u>			
	800 T/D	292,000 T	Green Coke
<u>Water Treatment</u>			
	1,200 lbs/day	219 T	Lime & Alum Flocculants
	50 lbs/day	9 T	Proprietary Coagulant Aid

*Water Excluded.

Source: U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado. Draft Environmental Impact Statement. DES-75-62. Washington, D.C. December 1975. p. II-48.

up to 30 years after initial operations.¹ The processed shale may have some commercial value: possible uses of processed shale are reported in Table 4-82.

Some of the other solid wastes from a surface processing facility may contain highly toxic substances such as arsenic, and could result in emission of hazardous materials during handling, disposal, or reprocessing. Hydrodenitrification catalyst, for example, may contain 8-10% sulfur and up to 7% arsenic after exhaustion. Regeneration or safe disposal is required.²

4.6.1.3d Noise Pollution

Noise levels within a shale processing facility have not been estimated. In general, retorting and upgrading processes produce noises similar to those produced during petroleum refining. The level of such noise depends on the specific retorting technology and upgrading sequence employed on site.³

Solids handling in the retort is probably one of the most significant noise-producing operations. Other noise sources in

¹Colley, J. D., W. A. Gathman, and M. L. Owen. Emissions from Synthetic Fuel Production Facilities. Prepared for U.S. Environmental Protection Agency. EPA Contract No. 68-02-3535. Austin, TX: Radian Corporation, September 1977. p. 6.

²Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. pp. 92-94.

³Conkel, N., V. Ellzey, and K. Murphy. Environmental Considerations for Oil Shale Development. Battelle Columbus Laboratories. Prepared for U.S. Environmental Protection Agency. October 1974. p. 81.

TABLE 4-82. POSSIBLE USES OF PROCESSED SHALE

Uses	Tons/Yr by 1980
A. Asphaltic concrete	300
B. Mineral wool	0
C. Lightweight aggregate - highway use	10,000
D. Lightweight aggregate - structural concrete and concrete blocks	250,000
E. Rubber filler	1,000
F. Road base and sub-base materials	40,000
G. Drilling mud	0
H. Oil well cements	0
I. Catalysts	0
J. Mineral fillers	0
K. Building brick	20,000
L. Portland cement	<u>250,000</u>
	571,300

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b.
Volume I. Prepared for Area Oil Shale Supervisor.
 February 1976. p. V-113.

the retort and upgrading facility include compressors, pumps, gearboxes, electric motors, and conduits. Administrative and engineering controls can insure that worker exposure to high sound pressure levels is within the limits established by the Occupational Health and Safety Administration. Noise levels at the boundaries of a shale processing facility are not expected to be "a nuisance".^{1, 2}

4.6.1.3e Occupational Health and Safety

Health and safety hazards associated with retorting and processing operations have not been extensively examined.

Safety hazards are described as "safety statistics" in the Hittman report. Using data estimated in Hittman for processing facilities employing USBM Gas Combustion or TOSCO II retorts, approximately 0.15 deaths and 15 injuries can be expected to occur annually at a 50,000 BPD processing facility. Lost working time can be expected to amount to 15 man-days for a TOSCO II processing facility to 40 man-days for a facility featuring the USBM Gas Combustion retort.³

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I. Prepared for Area Oil Shale Supervisor. February 1976. pp. V-51 to V-54.

²U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975, pp. IV-172 to IV-174.

³Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supplied by Emerging Technologies. Draft Report on Task 7 (Oil Shale) and Task 8 (Fluidized Bed Boiler Combustion). Prepared for Council on Environmental Quality, National Science Foundation, and Environmental Protection Agency. Contract EQC 308. Comumbia, MD, May 1974. p. V-27.

Health hazards for a processing facility are chiefly associated with worker exposure to raw and processed shale, shale oil and shale oil products, and toxic gases. Raw and processed shale contain silica, inorganic salts, toxic metals, and some toxic gases (as shown in Table 4-29 for raw shale, and Tables 4-74 through 4-76 for processed shale). Included among the organics are compounds that are known or suspected animal carcinogens, and that may be carcinogenic to man. Worker exposure to raw and retorted shale particulates has not been reported. Another potential hazard is exposure to arsenic-bearing dust.

Early awareness of the potential carcinogenicity of shale oils occurred in the British cotton industry. A high incidence of scrotal cancer was attributed to direct worker contact with shale oil lubricants used on spinning machings. Studies of workers in the Scottish oil shale industry during the same period did not reveal a particularly high cancer incidence. Studies of cancer incidence among Estonian shale workers also reported "normal" incidences of cancer. The National Institute of Occupational Safety and Health (NIOSH) is currently sponsoring a study of workers involved in the production of oil from Colorado oil shale.¹

Table 4-83 shows a comparison of the relative carcinogenic potency of several petroleum and oil shale derived materials. The indices suggest that shale-derived oils are similar to

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976. pp. 156-157.

TABLE 4-83. COMPARABLE CARCINOGENIC POTENCY
OF COMPLEX MIXTURES

Oil Product	Potency Index Based on Mouse Skin Tests
Industrial Fuel Oil	0.17
Naphthenic Distillate	0.06
Dewaxed Paraffin Distillate from Petroleum	0.06
Cracked Sidestream	0.26
Coke Oven Coal Tar	0.54
Crude Shale Oil	0.10
Upgraded Shale Oil	0.03
3-methylcholanthrene (reference compound)	1.0

Note: Index compares carcinogenic potency to a reference compound.
For example, upgraded shale is impotent compared to coke
oven coal tar.

Source: Coomes, R. M. "Health Effects of Oil Shale Processing",
9th Oil Shale Symposium, Colorado School of Mines,
April 29-30, 1976.

petroleum oils of comparable boiling range or intended use. Hydrotreating or upgrading shale oils reduces the carcinogenic potency.¹

Toxic gaseous emissions produced during retorting/upgrading operations have been previously described in Section 4.6.1.3a. Worker exposure to these gases has not been delineated.

4.6.1.3f Odor

Odors from shale retorting and processing include odors from sulfur oxides, nitrogen oxides, shale oil, and processed shale. Fumes from various distillates and chemicals are present from leaks in the upgrading plant. Some of these odors, particularly those associated with retorting, are similar to the odors of mined rock and local talus formations.^{2,3}

Some hydrogen sulfide is emitted, particularly during plant start-up and turnaround when high concentrations of H₂S are being flared. These odors are likely to be confined to the plant complex.

Inputs and outputs associated with a surface retorting/processing plant are summarized in Table 4-84.

¹Coomes, R. M. "Health Effects of Oil Shale Processing; 9th Oil Shale Symposium, Colorado School of Mines, April 29-30, 1976.

²U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975, p. IV-48.

³Based on semi-works operations.

TABLE 4-84. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH
A SURFACE RETORTING/PROCESSING PLANT PRODUCING
50,000 BPD OF SHALE OIL PRODUCTS^a

Inputs

Manpower	
• operating	429 men
• peak construction ^b	3300 men
Materials and Equipment	
• pyrolysis and oil recovery units	
• gas recovery and treating units	
• hydrogen production units	
• gas-oil and naphtha hydrogenation units	
• ammonia separation and sulfur recovery units	
• delayed coker	
• foul water stripping units	
• cement	9000 tons
• structural steel	6000 tons
• reinforcing bars and piping	2000 tons
• valves	2000
Economics ^c	
• capital	\$827,000,000
• annualized operating	\$126,000,000
Water	
• TOSCO II	5030 gpm
• Paraho ^d	3130-4150 gpm
• Union B ^d	2600 gpm
• Lurgi-Ruhrgas ^d	1470 gpm
• Superior ^d	3500 gpm
Land	1200-1500 acres
Ancillary Energy	
• TOSCO II	7×10^8 kwh/yr
• Paraho ^d	4.5×10^8 kwh/yr
• Union B ^d	6×10^8 kwh/yr
• Lurgi-Ruhrgas ^d	3×10^8 kwh/yr

(Continued)

TABLE 4-84. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH
A SURFACE RETORTING/PROCESSING PLANT PRODUCING
50,000 BPD OF SHALE OIL PRODUCTS^a (Continued)

Outputs

Air Emissions ^e	
• particulates	720-860 lb/hr
• hydrocarbons	950-1000 lb/hr
• NO _x	1630-1900 lb/hr
• CO	60-80 lb/hr
• SO ₂	270-350 lb/hr
• CO ₂	580,000 lb/hr
Water Effluents	No direct discharge
Solid Wastes	
• TOSCO II processed shale	53,000 TPD
• catalysts, sludges, etc.	1800 TPD
Noise Pollution	
• at plant boundaries	Negligible
Occupational Health and Safety	
• deaths	0.15/yr
• injuries	15/yr
• man-days lost	15/yr
Odors	Confined to plant site

^aInputs and outputs are based primarily on the TOSCO II process. When possible, inputs/outputs for other surface retorting technologies are presented. The plant produces a full range of products, as discussed in the text.

^bPeak for all phases (including mine construction)

^c1977 dollars

^dWater and energy requirements for Paraho, Union B, Lurgi-Ruhrgas, and Superior processes describe complexes with less extensive processing of the product shale oil than specified by TOSCO II developers. Please see the appropriate sections in the text for a discussion of these differences.

^eThese air emissions describe the TOSCO II processing complex; estimates for emissions from the Union B and Paraho retorts only are found in the text.

4.6.2 In-Situ Processing

4.6.2.1 Technologies

An alternative to surface preparation and retorting is underground or in-situ processing. In-situ processing includes fracturing the oil shale underground, introducing heat to cause pyrolysis underground, and conveying the product shale oil to the surface. As discussed in Section 4.5.3, modified in-situ processes fracture the oil shale by mining a portion of the shale, and blasting the remaining shale into the mined out void. True in-situ processes fracture the oil shale with one of several non-mining techniques. True in-situ processes proposed by the Laramie Energy Research Center and TRW, Inc. are discussed in Sections 4.6.2.1a and 4.6.2.1d. Modified in-situ processes developed by Occidental Oil Shale, Inc. and the Lawrence Livermore Laboratory are discussed in Sections 4.6.2.1b and 4.6.2.1c. A summary of other processes and activities is found below.

Reportedly the first attempt at in-situ oil shale processing was undertaken in the 1940's by the Estonians, who obtained products from a bed of Baltic Kukersite oil shale. During the same period (1944) the Swedes field tested a process (the Ljungstrom method) using electrical resistance heating in a Kvarntorp shale bed. These investigations were discontinued in the 1950's.¹

During World War II, Germany developed a modified in-situ process for the horizontal retorting of Wurttemberg oil shale. Shale oil yields seldom exceeded 30% of the Fischer assay.²

¹Prien, C. H. "LERC/ERDA In-Situ Oil Shale Research Program." In: Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. p. 99.

²*Ibid.*

In the early 1950's, Equity oil field tested several fracturing methods for developing in-situ retorts. One method combined hydrofracing (fracturing oil shale with water under pressure) with electrofracing (fracturing oil shale with electrical discharges) and explosive-fracing. The fractured shale bed was then retorted by hot natural gas injection. While this (and other methods) did produce oil, commercial development was not economically warranted.¹ Between 1965 and 1967 Equity conducted experiments in a naturally fractured shale zone deep in the center of the Piceance Creek Basin in Colorado using hot circulating methane gas. A -20°F pour point oil was produced, but methane loss was excessive. Atlantic Richfield reactivated the venture in 1968 and later (1970) used steam as the heat transfer medium. The project was terminated in 1971, but may be resumed.²

The Sinclair Oil and Gas Company conducted field studies in shallow oil shales (up to 300 feet deep) on the southern rim of the Piceance Creek Basin in 1953-54. A 31° API gravity, 2°C pour point oil was obtained. Field experiments in deeper shales were conducted in 1965. Results from and descriptions of these later efforts have not been published.³

Shell Oil has attempted solution mining of the minerals in oil shale to create permeability for retorting. No results from these efforts have been published and Shell appears to have discontinued this approach.⁴ Mobil Oil and Humble Oil have also

¹McCarthy, H. E. and C. Y. Cha. "OXY Modified In-Situ Process Process Development and Update." Quarterly of the Colorado School of Mines. 71(4): 87, October 1976.

²Prien, C. H. "LERC/ERDA In-Situ Oil Shale Research Program." In: Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. p. 100.

³*Ibid.*

⁴McCarthy, H. E. and C. Y. Cha, *op.cit.*, p. 87.

conducted field experiments in the Piceance Creek Basin using hot miscible fluids containing H₂S and/or other solubilizing agents. No results from any of these efforts have been published.¹

Dow Chemical conducted tests on an undescribed in-situ concept between 1956 and 1965.² Also, field tests have been conducted since 1975 on a true in-situ process for retorting low quality Michigan Devonian oil shales (typical yields of 10 or less gallons per ton of rock). The shale formation was fractured with chemical explosives detonated in two wells drilled 60 feet apart. Dow concluded that the detonation produced a relatively small amount of highly broken rock and left large volumes of rock untouched even very near the shot. Sustained combustion of the shale was not attained and the product off gas had a negligible heating value. No shale oil was recovered.³

Beginning in 1964 CER Geonuclear and a consortium of private companies proposed in-situ nuclear rubblization of shale and subsequent retorting at a Piceance Creek Basin site. A similar experiment was proposed for the Utah Oil Shales.⁴ The Lawrence Livermore Laboratories also considered detonating a

¹Prien, C.H. "LERC/ERDA In-Situ Oil Shale Research Program." In: Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. p. 100

²Musser, W.N. and J.H. Humphrey. "In-Situ Combustion of Michigan Oil Shale: Current Field Studies." 11th Intersociety Energy Conversion Engineering Conference Proceedings. v 1, pp. 341-348, 1976.

³Schora, F.C., P.M. Tarman and H.L. Feldkirchner. "State of the Art: In-Situ Shale Processing." Hydrocarbon Processing. March 1977, pp. 127-128.

⁴Prien, C.H., *op.cit.*, p. 100.

nuclear device to create a chimney of oil shale rubble.¹ Public opposition to the proposed nuclear experiments forced their cancellation.

Geokinetics, Inc. has begun field tests of its true horizontal in-situ process in the Uinta Basin (about 15 miles south of the federal lease oil shale tracts). Talley-Frac Corporation of Mesa, Arizona is considering an in-situ process with explosive fracturing of the shale formation. Geokinetics and Talley-Frac are two of four firms selected for cost-share funding under the Federal Non-Nuclear Energy Act of 1974. The other two firms are Equity Oil and Occidental Oil Shale.²

In 1975, Western Oil Shale Corporation and a 10-company consortium proposed a modified vertical in-situ project involving three underground retorts at a site in the Uinta Basin near Bonanza, Utah.³ A project involving a 3 year field test program costing \$25 to \$30 million has been proposed.⁴

4.6.2.1a LERC True In-Situ Process

In late 1965, the Laramie Energy Research Center of the U.S. Bureau of Mines (later LERC/ERDA) began a series of field experiments on in-situ fracturing and retorting of oil shale at sites

¹McCarthy, H.E. and C.Y. Cha. "OXY Modified In-Situ Process Development and Update." Quarterly of the Colorado School of Mines. 71(4): 88, October 1976.

²Prien, C.H. "LERC/ERDA In-Situ Oil Shale Research Program." In: Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976. pp. 100, 108.

³*Ibid.*, p. 100.

⁴Schora, F.C., P.M. Tarman and H.L. Feldkirchner. "State of the Art: In-Situ Shale Processing." Hydrocarbon Processing. March 1977, pp. 127-128.

near Rock Springs, Wyoming. Various combinations of electrofracing, (fracturing with electrical discharges), hydrofracing (fracturing with water under pressure), and explosive-fracing were used to fracture the shale formations. Concurrent with the field tests, LERC conducted simulated in-situ tests using large shale pieces in a 10-ton batch scale retorts (beginning in 1965) and a 150-ton retort (beginning 1969). These batch retorts are still used for evaluation of in-situ engineering parameters.¹

Figure 4-27 is a schematic of the LERC process. The process involves first boring injection and production wells into the oil shale formation. The shale is then fractured by a combination of electrofracing, hydrofracing and/or explosive-fracing. Fracturing occurs along horizontal planes. In LERC's latest test, retorting is initiated by heating the edge of the shale formation with the flame formed by combustion of compressed air and propane. When the temperature is high enough to combust the carbonaceous residue in the retorted shale, compressed air alone is injected to the formation. Heat from the combustion of the carbonaceous residue decomposes the kerogen into gases, water vapor, and shale oil mist. Pressure from the injection wells forces the oil along the fracture lines toward the production wells, through which the oil is recovered.²

In theory, the process operates like a horizontal retort, with a retorting zone advancing across the formation ahead of a combustion zone. The latest test produced oil with a gravity of 26°API and a pour point of 4°C. The off gas had a net heating

¹Prien, C. H. "LERC/ERDA In-Situ Oil Shale Research Program." In: Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976.

²*Ibid.*, p. 101-105.

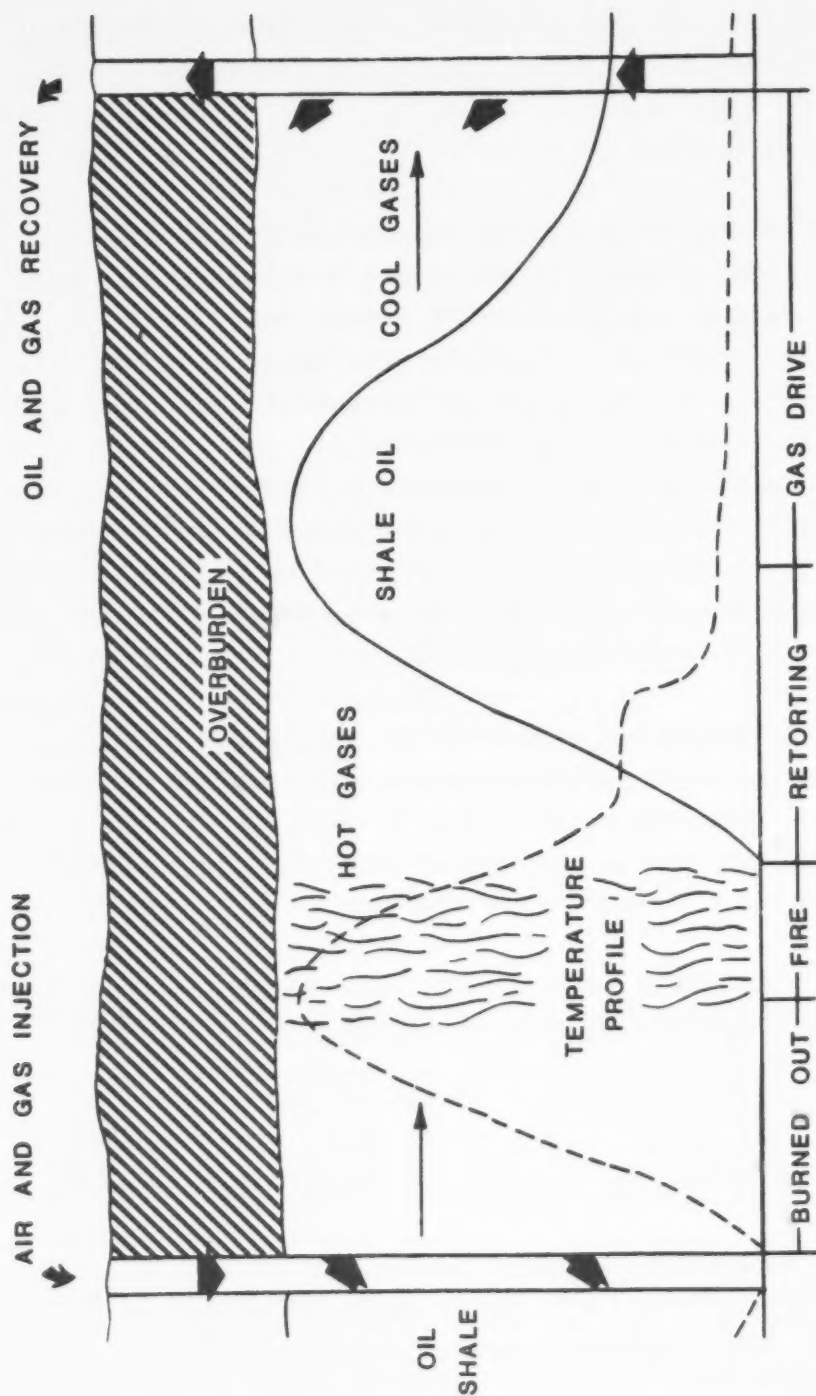


Figure 4-27. Simplified schematic of LERC true in situ process.

Source: U.S. Department of the Interior, Final Environmental Statement for the Prototype Oil Shale Leasing Program 6 Vols. Washington, D.C. Government Printing Office, 197 Vol. I, p. 1-37.

value of 30-40 Btu/ft³ (267-356 kcal/m³). Oil yields from the process were low due to poor fracturing of the shale bed.¹

4.6.2.1b Occidental Process

The OXY process was conceived by Occidental Petroleum's in-house research firm, Garrett Research and Development Co., in the late 1960's. During May of 1972, US Patent 3,661,423, "In-Situ Process for Recovery of Carbonaceous Materials from Subterranean Deposits", was assigned to Occidental Petroleum. Site development for field testing commenced in July 1972 at the head of Logan Wash, outside of Debaque, Colorado. In the ensuing months, three research retorts were prepared and ignited. At the end of 1974, the project was transferred to Occidental Oil Shale, Inc. upon its establishment as a subsidiary of the Occidental Oil and Gas Production Division.^{2,3}

The original test program consisted of mining and retorting three in-situ retorts, each approximately 1,000 square feet in cross-section and varying in height from 72 to 114 feet. By the end of the test program, total production from the three retorts had amounted to over 4,000 barrels of shale oil.⁴

¹Prien, C.H. "LERC/ERDA In-Situ Oil Shale Research Program." In: Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976.

²Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b. Prepared for the Area Oil Shale Supervisor. February, 1977. p. II-1 to 4.

³Shih, C.C. "Occidental Modified In-Situ Process." In: Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. December 1976.

⁴Ashland Oil, Inc., *op.cit.*, p. II-1 to 4.

Development of the first commercial-size retorts commenced in early 1975. The first retort (No. 4) measured 120 by 120 feet in cross-section with a height of 270 feet. This retort was rubbled August 10, 1975 and ignited on December 10, 1975. The burn was continued successfully until June 1976, and produced 27,500 gallons of shale oil. Two other commercial-size retorts are currently being developed.^{1,2}

In late 1976, Occidental Oil Shale entered into a partnership with Ashland Oil for the development of oil shale tract C-b in Rio Blanco County, Colorado. Site preparations for the development of initial test retorts commenced in September 1977. Concurrent with the development of two test retorts, Occidental plans to begin development of a commercial-scale mining complex. Prior to full-scale operations four or more retorts will be operated as a retort cluster to gain operating experience. Ultimately, 57,000 barrels of shale oil are to be produced daily from 40 operating retorts. Occidental expects full-scale production to begin in 1983.³

The U.S. Department of Energy (DOE) is funding a portion of Occidental's development activities. The DOE is providing 71% of some \$60.5 million estimated for a 53-month project period. The first phase of this effort, costing \$19.4 million, evaluates Occidental's two retort designs at the Logan Wash test site in Garfield County, Colorado. (These retort designs are described

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b. Prepared for the Area Oil Shale Supervisor. February, 1977. p. II-1 to 4.

²Shih, C.C. "Occidental Modified In-Situ Process." In: Technological Overview Reports for Eight Shale Oil Recovery Processes. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976.

³Ashland Oil, Inc. *op.cit.*

in Section 4.5.3.1). One of these designs will then be demonstrated at oil shale tract C-b in Rio Blanco County Colorado.

In the Occidental process, air is forced into the operating retorts by gas blowers located on the surface. These blowers maintain a negative pressure on the entire retort and gas-gathering system. The air flows to the retorts from the service shaft via a network of upper-mine-level air "drifts" or tunnels (as shown in Figure 4-28). Steam is piped to the operating retorts from steam boilers located on the surface. The process air and steam are then mixed in individual feed entries connecting retorts to the air level drifts.¹

Retorting is initiated by heating the top of the rubble shale column with the flame formed from the combustion of air and an external source (propane, natural gas or raw shale oil). Temporary startup burners are set in the feed entries. These burners are operated until a temperature is attained that is high enough to combust the carbonaceous residue in the retorted shale.²

Flame front movement in the OXI process is shown in Figure 4-28. At the top of the retort, the air/steam feed gas is preheated by hot spent shale. In the combustion zone, oxygen from the air is reacted with residual carbon and oil at temperatures of 1300-1500°F. Below the combustion zone is the retorting zone where hot combustion gases heat the raw shale rubble to a temperature of about 900°F. The kerogen or organic material in the raw shale is decomposed by the heat to bitumen and ultimately

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b. Prepared for the Area Oil Shale Supervisor. February, 1977. p. III-32.

²*Ibid.*

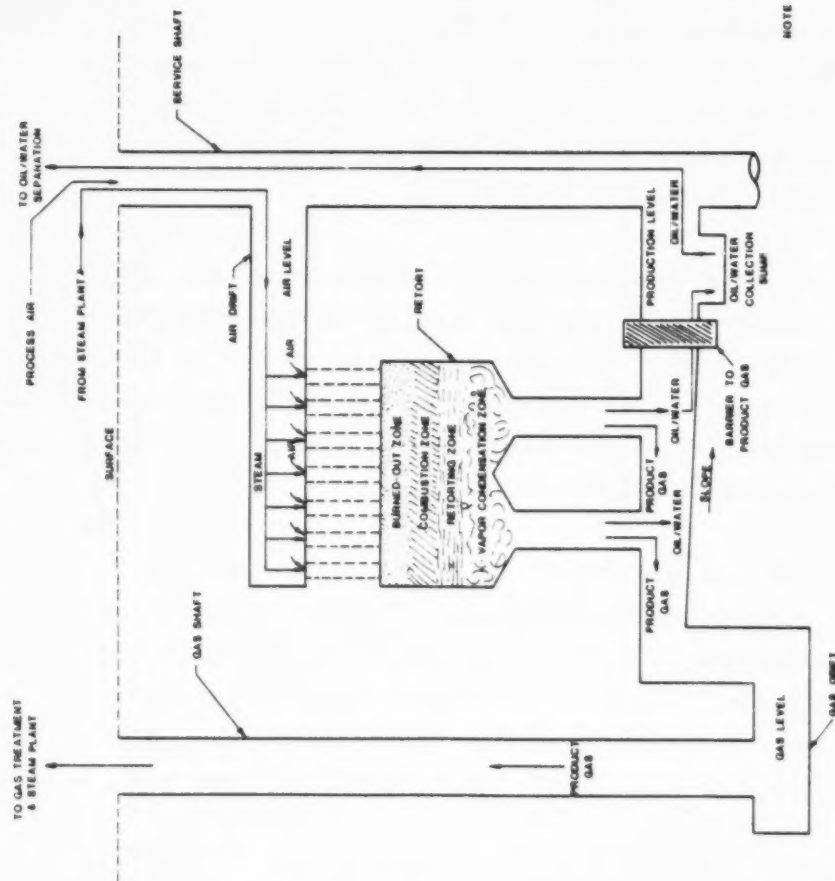


Figure 4-28. Simplified Drawing of an Operating Retort.

Source: Ashland Oil, Inc. and Occidental Oil Shale, Inc.
 Supplemental Material to Modified Detailed Develop
 ment plan for Oil Shale Tract C-b. Prepared for
 Area Oil Shale Supervisor. June 1977.

to gas, oil, and solid residue. In the vapor condensation zone, the combustion and retorting gases are cooled by unretorted shale, and oil and water are condensed.^{1, 2}

The product gas, oil, and water flow out the bottom of the operating retorts. The product gas is collected in lateral drifts on the mine production level. These drifts are isolated from fresh air drifts. Each lateral drift is connected to a totally isolated main-gas-collection drift located below the production level. This drift conveys all of the product gas to the surface via the gas shaft.³

At the surface, gas is discharged to the gas treatment units. Hydrogen sulfide is removed from the gas stream in gas treatment units by using a Stretford-type or equivalent process. In the Stretford process, hydrogen sulfide is absorbed in an alkaline liquid and directly oxidized to elemental sulfur by dissolved vanadium compounds and an oxidation catalyst.⁴

The gas leaves the gas treatment units and is burned in boilers similar to those used in refineries to burn carbon monoxide. These product gas boilers are specially designed for firing with low-heating-value gas. All steam requirements for the OXY process are met by steam produced from the product gas boilers. Heat from the combustion of the product off-gas can

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b. Prepared for the Area Oil Shale Supervisor. February, 1977. p. III-32.

²Chew, R.T. "Operations and Environmental Considerations, Occidental Petroleum Corporation In-Situ Operations." In: Science and Technology of Oil Shale, T.F. Yen (ed.). Ann Arbor Science Publishers, Ann Arbor, Michigan, 1976, pp. 73-81.

³Ashland Oil, Inc., *op.cit.*, p. III-33.

⁴*ibid.*

also be used for electricity generation. (Although the potential has not been determined, Occidental has suggested that all steam and electricity requirements of the process can be fulfilled by combustion of the off gas.) Product gas flaring capacity is also required for process startup and upset conditions.¹

The spent Stretford liquor from the gas treatment units contains suspended particles of elemental sulfur. This spent liquor is regenerated in an aeration basin by reoxidation of the vanadium with air. Sulfur floats to the surface of the basin in a foam which can be skimmed off into a froth basin. From the froth basin the separated sulfur slurry is pumped through a sulfur melter into a decanter where liquid sulfur product is withdrawn. The Stretford liquid from the decanter is then returned to the oxidizer basin.²

The oil and water from operating retort clusters flow through a sloped conduit by gravity to a central oil/water collection sump. Oil and water are then pumped up the production and service shafts to oil/water separation facilities on the surface.³

On the surface, free water is separated from the product oil by gravity in a primary separator. The "wet" oil is then pumped to heater/treaters for secondary water separation. Essentially water-free oil is withdrawn from the heater/treater and routed to product storage. Recovered water is routed to treatment facilities or ponds.⁴ Crude shale oil withdrawn from the heater/treater has properties similar to those shown in Table 4-85.

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b. Prepared for the Area Oil Shale Supervisor. February, 1977. p. III-34.

²*Ibid.*, p. III-33 to 34.

³*Ibid.*, p. III-33.

⁴*Ibid.*

TABLE 4-85. PROPERTIES OF CRUDE SHALE OIL PRODUCED FROM THE
OCCIDENTAL IN-SITU PROCESS

Gravity	24-25°API
Specific Gravity (60°F/60°F)	0.9
Pour Point	65-70°F
	18-21°C
Viscosity (100°F)	70-116 SUS

Elemental Composition (by weight)

Carbon	84.86%
Hydrogen	11.80%
Nitrogen	1.50%
Oxygen	1.13%
Sulfur	0.71%

C/H Ratio 7.19

Oil Composition (by Volume)

Naphtha, IBP to 400°F	4.6%
Light Distillate, 400-600°F	25.4%
Light Gas Oil, 600-800°F	45.0%
Heavy Gas Oil, 800-1000°F	20.0%
Residium, over 1000°F	5%

References: McCarthy, H.E., and C.Y. Cha. "OXY Modified In-Situ Process Development and Update." Quarterly of the Colorado School of Mines. 71(4): 85-100, October 1976.

McCarthy, H.E., and C.Y. Cha. "Development of the Occidental Modified In-Situ Oil Shale Process" 68th AIChE Annual Meeting, Los Angeles, California, November 16-20, 1975.

Oil produced from in-situ retorting has a lower pour point and viscosity than oils produced from surface retorting, and can be pipelined without further treatment. Oil produced from in-situ retorting is also more highly saturated than oils produced from surface retorting. Crude shale oil produced from in-situ retorting also contains less nitrogen than oils produced from ex-situ retorting.

Oil yields for the OXY process range from 60 to 70 percent of the Fisher assay of the rubbled shale. The target shale interval in oil shale tract C-b contains about 3.0 billion barrels of oil in place. Of this, about 1.2 billion barrels are to be recovered by the OXY In-Situ Process. An additional 0.45 billion barrels can be recovered by surface retorting mined-out shale. Overall resource recovery without surface retorting amounts to 40% of the oil in place. Overall recovery with surface retorting amounts to 55% of the oil initially in place.¹

4.6.2.1c RISE (Rubble In-Situ Extraction) Process

The RISE process was conceived by the Lawrence Livermore Laboratory (at the University of California) in the early 1970's. Large-scale tests to simulate below-ground processing have been conducted along with a variety of small-scale tests and mathematical modeling programs. The process has not yet been field-tested.²

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b. Prepared for the Area Oil Shale Supervisor. February, 1977. p. I-9.

²Schora, F.C., P.M. Tarman and H.L. Feldkirchner. "State of the Art: In-Situ Shale Processing." Hydrocarbon Processing. March 1977. pp. 127-128.

The RISE process is a modified in-situ process conceptually similar to the OXY process. As reported in Section 4.5.3.1, the RISE rubble column is created by a continuous mining process using a modified sublevel caving technique. This procedure presumably prepares rubble of more uniform size than the OXY process. The proposed mining technique also permits continual measurement of rubble size. Commercial-size retorts formed by the mining process are expected to be 150 feet wide by 300 feet long by a nominal 750 feet high.¹ The RISE process is thus more desirable for thick oil shale formations.^{2,3,4} A diagram of the proposed mining technique is found in Section 4.5.3.1.

The rubble column is retorted by heating the oil shale with a hot gas. This hot gas can be continuously generated by combusting a portion of the oil shale with an air stream (as in the OXY process). It is also possible to heat a gas by external combustion and circulate it through the oil shale rubble.⁵

Detailed plans for the development of the RISE process were approved by the U.S. Department of the Interior in late 1977.

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a. 3 Volumes. Prepared for Area Oil Shale Supervisor. May 1977.

²Shora, F.C., P.M. Tarman and H.L. Feldkirchner. "State of the Art: In-Situ Shale Processing." Hydrocarbon Processing. March 1977. pp. 127-128.

³Rothman, A.J. "Research and Development on Rubble In-Situ Extraction of Oil Shale (RISE) at Lawrence Livermore Laboratory." Colorado School of Mines Quarterly. 70(3) 159-78 (1975).

⁴Lewis, A.E., et al. "Rubble In-Situ Extraction (RISE): A Proposed Program For Recovery of Oil From Oil Shale." Lawrence Livermore Laboratory. UCRL-51768. March 5, 1975. p. 26.

⁵*Ibid.*

Initial development of the Rise process will be undertaken by Gulf Oil Corporation and Standard Oil Company (Indiana) on oil shale tract C-a in Rio Blanco County, Colorado. Commercial operations are tentatively expected to begin in 1987.¹

Preliminary development plans anticipate the surface processing of mined-out shale. This development option is discussed further in Section 4.6.3, Modified In-Situ and Surface Processing.

4.6.2.1d In-Situ Retorting with Mineral Recovery

A novel process for the in-situ recovery of oil and minerals from Piceance Creek Basin (Colorado) oil shale has been proposed by the Energy Systems Group of TRW, Inc. The process is designed to recover nahcolite, alumina, and shale oil from the salt-capped shale deposit at the center of the Piceance Creek Basin. The shale formation at the center is gas tight, free of aquifers, and rich in dissolved minerals, but lies beneath a thick overburden. Although the process has not been field-tested, small-scale laboratory data indicate that the process is conceptually feasible. TRW has proposed a development program to assess the commercial feasibility of the process.²

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 Volumes. Prepared for Area Oil Shale Supervisor. May 1977.

²Cowles, J. O. and E. M. Boughton. "In-Situ Recovery of Oil and Minerals from Piceance Creek Basin Oil Shale." 11th Inter-society Energy Conversion Engineering Conference Proceedings, 1976. VI, pp. 336-340.

The TRW process comprises several steps: solution mining, retorting, alumina extraction, and residue combustion. Solution mining of nahcolite (NaHCO_3) is accomplished by injecting steam into the top of the shale formation. Condensed water saturated with sodium salts is then collected at the bottom of the formation. After nahcolite removal, the shale deposit is full of heated and rubblized oil shale with about 20 percent interconnected void space.^{1,2}

Hot gas is then forced into the shale formation to retort the kerogen in the oil shale. Lighter retorting products are swept to the surface in the vapor phase. Heavier liquids accumulate at the bottom of the retorted zone and are subsequently pumped to the surface.³

At the temperatures required to decompose the kerogen, natural dawsonite ($\text{NaAl}(\text{OH})_2\text{CO}_3$) is converted to a soluble form of alumina ($\text{Al}_2\text{O}_3 \cdot 2\text{H}_2\text{O}$). The next process step (following retorting) is extracting this soluble alumina from the residual shale rubble. The alumina-rich solution is then brought to the surface. $\text{Al}(\text{OH})_3$ is precipitated by pumping carbon dioxide

¹Cowles, J. O. and E. M. Boughton. "In-Situ Recovery of Oil and Minerals from Piceance Creek Basin Oil Shale." 11th Intersociety Energy Conversion Engineering Conference Proceedings. 1976. VI, pp. 336-340.

²Beard, N. T. "A Process for Solution Mining Nahcolite", U.S. Patent 3779602 and "Method of Producing Hydrocarbons from an Oil Shale Formation:", U.S. Patent 3759574. As cited in: "In-Situ Recovery of Oil and Minerals from Piceance Creek Basin Oil Shale." 11th Intersociety Energy Conversion Engineering Conference Proceedings. 1976. VI. pp. 336-340.

³Cowles, J. O. and E. M. Boughton, *op.cit.*

into the saturated solution. The alumina extraction step has been demonstrated in the laboratory by the USBM.^{1,2}

The leached, retorted zone will contain some residual oil, char and unretorted kerogen. A final combustion step may provide enough low grade heat to supply all other process energy needs, and possibly some carbon dioxide for the precipitation of alumina.³

4.6.2.2 Input Requirements

This section reports inputs required for retorting and processing operations at a modified in-situ facility. Detailed estimates of the various manpower, equipment, water, land, and energy requirements are largely based on data reported by Occidental Oil Shale in the 1977 Modifications to the Detailed Development Plan (MDDP) for Oil Shale Tract C-b. Estimates of the capital requirements and annualized operating costs are likewise based on data reported by Occidental in the MDDP. The inputs reported for the OXY process are probably similar to those inputs required for other modified in-situ processes (e.g., the RISE process). While Occidental's plan was specifically contrived for development on tract C-b, input requirements for facilities at other locations are probably not significantly different.

¹Cowles, J. O. and E. M. Boughton. "In-Situ Recovery of Oil and Minerals from Piceance Creek Basin Oil Shale." 11th Inter-society Energy Conversion Engineering Conference Proceedings. 1976. VI, pp. 336-340.

²Smith, J. W. and N. B. Young. "Dawsonite: Geochemistry, Thermal Behavior and Extraction from Green River Oil Shale." Quarterly of the Colorado School of Mines, 70(3): 69-94. As cited in: Cowles, J. O., *op.cit.*

³Cowles, J. O. and E. M. Boughton, *op.cit.*

The inputs presented below describe a modified in-situ process simply disposing of raw mined-out shale. Inputs required for a modified in-situ process with the surface retorting of mined-out shale are discussed in Section 4.6.3.2.

4.6.2.2a Manpower

Manpower requirements for the full scale operation of an in-situ facility are reported in Table 4-86. These requirements include those personnel required for retorting and processing operations. Manpower requirements for mining operations are reported in Section 4.5.3.2, Mining for In-Situ Processing. The manpower requirements are those reported by Occidental for 57,000 bbl/d facility.

The manpower requirements in Table 4-86 relate only those requirements for full-scale commercial operations. Occidental has not reported skill breakdowns for the construction personnel required to establish the site prior to commercial operation. However, construction manpower requirements have been included in the total program manpower requirements previously shown in Figure 4-14. The manpower requirements in Figure 4-14 assume a three-stage development of the in-situ complex. The first stage involves the construction and operation of initial test retorts. The second stage includes construction and operation of one or two retort clusters to train operating personnel and confirm operating techniques. Construction of the full-scale complex also begins in this stage. The final stage is the full-scale commercial operation of the in-situ facility. After initial demonstration of the OXY process, the development stages may be shortened to take advantage of previous developments.

TABLE 4-86. MANPOWER REQUIREMENTS FOR IN-SITU
RETORTING AND PROCESSING OPERATIONS
PRODUCING 57,000 BPD

PERSONNEL	NUMBER REQUIRED
Process Operators	
Operations Superintendent	1
Assistant Superintendent	1
Chief Supervisor (Underground)	1
Chief Supervisor (Surface)	1
Shift Supervisor (Underground)	4
Shift Supervisor (Surface)	4
Operations Engineer	2
Area Engineer	6
Safety Supervisor	1
Laboratory Supervisor	1
Chemist	1
Laboratory Technician	8
Chief Clerk	1
Assistant Clerk	1
Secretarial/Clerical	10
Lead Operator	36
Operator	72
Construction/Startup Operator	67
Maintenance and Utilities Personnel	
Machinist	6
Electrician	20
Pipe Fitter	12
Mechanics-Auto	15
Sheet Metal	15
Instrument Technician	14
Welder	20
Tool Crib	8
Laborers	20
Mobile Equipment	10
Bus Driver	45
Area Maintenance Mechanic	70
Boiler Plant Operator	4
Warehouseman	12
Machine Shop Foreman	1
Electrical Foreman	1
Pipe Fitter Foreman	1
Instrument Foreman	1
Welder Foreman	1
Area Maintenance Foreman	1
Warehouse Foreman	1
Machine Shop Assistant Foreman	1

(Continued)

TABLE 4-86. MANPOWER REQUIREMENTS FOR IN-SITU
RETORTING AND PROCESSING OPERATIONS
PRODUCING 57,000 BPD (Con't)

PERSONNEL	NUMBER REQUIRED
Maintenance and Utilities Personnel (Cont'd.)	
Electrical Assistant Foreman	1
Pipe Fitter Assistant Foreman	2
Instrument Assistant Foreman	4
Welder Assistant Foreman	1
Area Maintenance Assistant Foreman	1
Warehouse Assistant Foreman	1
Security Chief	1
Security Guards	24
Instrument Superintendent	1
Instrument Engineer	2
Clerks	10
General Administration and Support Personnel	<u>16</u>
TOTAL	561

Reference: Ashland Oil, Inc. and Occidental Oil Shale, Inc.
Supplemental Material to Modifications to Detailed
Development Plans for Oil Shale Tract C-b, prepared
for Area Oil Shale Supervisor, July 21, 1977.

4.6.2.2b Materials and Equipment

Detailed materials and equipment requirements have not yet been prepared by Occidental. Facilities required for operation of the in-situ complex include: gas treatment unit(s), product gas boilers, oil/water separation equipment, blowers, water treatment facilities, and product oil storage tanks. Gas treatment units are required to remove hydrogen sulfide from the product off-gas. The product off-gas is then burned in boilers similar to those used in refineries to burn carbon monoxide. Oil/water separation includes gravity separation and secondary separation. Free water is separated from the product oil by gravity in a primary separator. The "wet" oil is then pumped to heater/treaters for secondary separation. Gas blowers maintain the flow of air and product gas through the retort. Various water treatment facilities are required to treat the various wastewater streams in the process (as described in Section 4.6.2.3b).¹

4.6.2.2c Economics

Preliminary capital cost estimates for a 57,000 bbl/d shale oil complex are shown in Table 4-87. These costs have been reported by Occidental in the MDDP for oil shale tract C-b, and should not be misconstrued as definitive cost estimates. The estimates are based only on preliminary engineering design and process scheduling. The costs shown in Table 4-87 do not include interest accrued during construction or deferred capital expenditures. The total installed equipment costs include those costs

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b. Prepared for the Area Oil Shale Supervisor. February, 1977.

TABLE 4-87. CAPITAL COST ESTIMATES FOR
AN IN-SITU OIL SHALE COMPLEX
PRODUCING 57,000 BPD^a

COMPONENT COST	COST
Oil and Gas Processing	
Steam Generation Plant	\$ 21,060,000
Water Treatment Plant	36,250,000
Gas Treatment Plant and Heater Treater	10,200,000
Other Major Equipment	15,568,000
Other Materials	12,405,000
Taxes, Spare Parts, and Miscellaneous	3,036,000
Field Indirects	<u>4,519,000</u>
Subtotal	\$103,038,000
General Facilities	
Emergency Generating Equipment, Package Boiler, Hoist, Cranes, Air Compressors, Storage Tanks, and Miscellaneous Equipment	} 9,532,000
Direct Materials, Concrete, Electrical Insulation, Roads, and Other Civil Work	
Other Direct Costs, Spare Parts, Taxes, etc.	2,984,000
Field Indirects	<u>10,378,000</u>
Subtotal	\$ 83,892,000
TOTAL INSTALLED EQUIPMENT ^c	\$323,716,000
Contractors Engineering, Home Office, Fees, Working Capital, Contingency	118,893,000
TOTAL INVESTMENT	\$442,609,000

^aCosts are in 1977 dollars and are those reported by Occidental

^bCosts include costs for mine equipment

Reference: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b.
Prepared for the Area Oil Shale Supervisor. February, 1977.
p. I-11.

reported in Section 4.5.3.2 for in-situ mining. Miscellaneous capital requirements (i.e., costs for general facilities, indirects, and working capital) for the entire in-situ complex are also included in Table 4-87.¹ The total investment (including mine facilities) for an in-situ facility producing 57,000 bbl/d is shown as \$442,609,000.

Operating costs estimates for the OXY process were not reported in the MDDP or in the Supplement to the MDDP. However, data reported in the MDDP (and its supplement) can be used to contrive preliminary cost estimates. These estimates are shown in Table 4-88, and are based on preliminary, incomplete data. The labor costs are estimated from the labor requirements reported by Occidental in the Supplement to the MDDP. Utilities' costs are estimated from the power and fuel requirements reported in the MDDP and its supplement. All other costs are estimated as percentages of the capital or labor costs. Total annualized retorting and processing costs are shown as \$76,000,000.

4.6.2.2d Water

A modified in-situ process requires water for dust control, steam and/or power generation, miscellaneous utilities, sanitary use, and revegetation. Water required for dust control is more closely associated with mining operations and is discussed in Section 4.5.3.2. Similarly, water required for the revegetation of mined-out shale is discussed in Section 4.7, Reclamation. The other major uses of water are described below.

Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b,
Prepared for the Area Oil Shale Supervisor. February 1977.
p. I-11.

TABLE 4-88. ANNUALIZED OPERATING COSTS FOR
AN IN-SITU OIL SHALE COMPLEX
PRODUCING 57,000 BPD^a

COMPONENT	COST	
Direct Costs		
Process Operators	\$ 3,400,000 ^b	
Maintenance and Utilities Personnel	5,000,000 ^b	
General Administration and Support Personnel	<u>240,000^b</u>	
	\$ 8,600,000	
Operating Supplies	1,900,000 ^c	
Maintenance Materials	9,400,000 ^d	
Utilities		
Electricity	27,000,000 ^e	
Water ^f	-	
Surface Fuel Requirement ^g	-	
Fixed Costs		
Depreciation	19,000,000 ^h	
Taxes and Insurance	5,600,000 ⁱ	
Plant Overhead	<u>4,300,000^j</u>	
TOTAL	\$76,000,000	\$3.65/bbl

^aCosts are in 1977 dollars

^bCalculated @ \$20,000/man-year for staff, and @ \$15,000/man-year for labor

^cCalculated @ 1% of fixed capital costs

^dCalculated @ 5% of fixed capital costs

^eCalculated @ \$0.04/kwh

^fWater costs have not been specified and are probably not significant. Power costs include power costs for water treatment

^gSurface fuel requirements are unknown but are probably insignificant

^hCalculated @ 10% of fixed capital costs

ⁱCalculated @ 3% of fixed capital costs

^jCalculated @ 50% of total labor costs

References: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to the Detailed Development Plan for Oil Shale Tract C-b. Prepared for the Area Oil Shale Supervisor. February, 1977. p. II-1 to 4.

Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Detailed Development Plan Modifications for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor, July 21, 1977.

Major water requirements for a 57,000 bbl/d facility are summarized in Table 4-89. Occidental's MDDP reports the total water requirements for the in-situ facility as 2500 gpm. Thus, the production of 1 barrel of shale oil requires about 1.5 barrels of water. Occidental recently, however, reported that the production of 1 barrel of oil may require 1.8-1.9 barrels of water. Total requirements for a 57,000 BPD facility would then be 3000 to 3200 gpm.¹ Most of the water is required for steam generation. For Occidental's proposed 57,000 bbl/d facility, steam generation water requirements amount to 1800 gpm. About 300 gpm are required for miscellaneous utilities (primarily cooling water). Water requirements for personnel are not significant.²

Groundwater seepage in the underground complex is expected to supply most of Occidental's process water needs. For example, groundwater can fulfill steam generation water requirements after undergoing 1) filtration, 2) addition of chemicals for scale control, 3) reverse osmosis, and 4) deionization and deaeration. Filtered and treated groundwater can also be used to meet utility water requirements. The desirability and availability of groundwater for these uses are dependent on the site of the in-situ development.³

Another source of process water is the return condensate from miscellaneous utilities. Most of the 300 gpm required for miscellaneous utilities can be recycled for reuse. Net process makeup water requirements have been estimated as 100-500 gpm.⁴

¹Conversation with Ms. Marnie Talbert, Occidental Oil Shale, Inc. October 13, 1977.

²Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-5. Prepared for Area Oil Shale Supervisor. February, 1977. pp. III-43 to 45, Figure III-J.

³*Ibid.*

⁴*Ibid.*

TABLE 4-89. SUMMARY OF WATER REQUIREMENTS FOR A MODIFIED IN-SITU FACILITY PRODUCING 57,000 BBL OF SHALE OIL PER DAY

Steam Generation	1800 gpm ^a
Miscellaneous Utilities	300 gpm ^b
Dust Control	<u>450 gpm^c</u>
TOTALS	2500 gpm ^d

^aBased on 850,000 lbs of steam produced per hour, with a boiler water blowdown of 100 gpm.

^bPrimarily cooling water.

^cAssociated with mining operations; described in Section 4.5.3.2.1.

References: Ashland Oil, Inc. and Occidental Oil Shale, Inc.:
Modifications to Detailed Development Plan for Oil
Shale Tract C-b. Prepared for Area Oil Shale
Supervisor. February, 1977. pp. III-43 to 45,
Figure III-J.

4.6.2.2e Land Requirements

Occidental has estimated the surface land areas disturbed by an in-situ development. In the development of a 57,000 bbl/d facility, approximately 80 acres are required for surface processing facilities.¹ The additional land areas required for shale disposal, mine development and road construction are delineated in Section 4.5.3, Mining for In-Situ Processing.

4.6.2.2f Ancillary Energy Requirements

Ancillary energy requirements for an in-situ complex have been reported by Occidental and are tabulated in Table 4-90. Electricity requirements for retorting/processing operations amount to approximately 6.7×10^8 kwh/year. These estimated requirements assume that no electric power is generated on-site. (Although the potential has not been determined, Occidental has suggested that all steam and electricity requirements can be fulfilled by combustion of the product off-gas.) More than half of the power demands are associated with the operation of the gas blowers. Sixty to 70 percent of the energy of the rubbled shale is recovered as crude shale oil. Forty percent of the energy of the target shale interval is recovered as crude shale oil.²

4.6.2.3 Outputs

This section reports the various outputs associated with the operation of a modified in-situ facility. Discussions of air emissions, water effluents, solids wastes, and noise pollution

¹ Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-5. Prepared for Area Oil Shale Supervisor. February, 1977. p. I-13.

² *Ibid.*, p. I-9.

TABLE 4-90. ANCILLARY ENERGY REQUIREMENTS FOR
AN IN-SITU OIL SHALE FACILITY
PRODUCING 57,000 BPD

Category	Power Requirement	Energy Usage
Electricity		
Product Oil/Water Pumps	6,400 hp	4.2×10^7 kwh/year ^a
Gas Treatment	12,000 hp	7.8×10^7 kwh/year ^a
Product Oil Treatment	4,000 hp	2.6×10^7 kwh/year ^a
Steam Generation	800 hp	0.5×10^7 kwh/year ^a
Process Blowers	66,800 hp	4.4×10^8 kwh/year ^a
Water Treatment	6,200 hp	4.4×10^7 kwh/year ^a
Sulfur Recovery	2,000 hp	1.3×10^7 kwh/year ^a
General Services	-	2.1×10^7 kwh/year ^a
TOTAL		6.7×10^8 kwh/year ^{a, b}
Diesel Fuel		
	- ^c	

^a Assumes operation 8760 hours/year; 1 hp = 7.457×10^{-1} kw.

^b Figure represents electricity directly used in retorting/processing.
Gross power plant energy requirements can be estimated by using power
plant heat rate of 9750 Btu/kwh (power generation efficiency of 35%).

^c Surface fuel requirements are unknown.

Reference: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications
to Detailed Development Plan for Oil Shale Tract C-b. Prepared
for Area Oil Shale Supervisor. February, 1977. p. III-39.

are largely based on information reported by Occidental in the MDDP and its supplement. Although Occidental's data are specific to oil shale tract C-b (in Rio Blanco County, Colorado), outputs for in-situ development at other locations are probably very similar. However, the environmental impacts from these outputs do vary from site to site. Outputs for mining and shale disposal are described in Section 4.5.3.3.

4.6.2.3a Air Emissions

Air emissions from retorting/processing operations at a modified in-situ complex originate from steam generation, shale oil storage, gas treatment, and wastewater treatment. Emissions from these operations are described below. Quantitative estimates are available only for emissions from steam generation and shale oil storage.

As described previously, product gas from retorting first undergoes H₂S removal in a Stretford-type treatment unit. The treated gas is then combusted in the fireboxes of the product gas boilers to generate steam. Emissions from the steam plant are summarized in Table 4-91. Estimates for the emissions of non-criteria pollutants have been reported only for mercury and arsenic. Retorting temperatures and conditions are not severe enough to volatilize most metals and heavy elements.¹

Particulates emitted from the steam plant contain the same elements and compounds found in retorted shale. Unfortunately, analyses of the elemental and mineral content in in-situ retorted shale have not been reported. Analyses of the element

¹Crawford, K.W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976.

TABLE 4-91. RETORTING/PROCESSING EMISSIONS FROM AN IN-SITU OIL SHALE COMPLEX, LB/HR^a

Pollutant	Steam Plant Flue Gas ^{b,c}	Tank Storage
Particulate	<74	-
SO ₂	174	-
CO	84	-
THC	15	103
NO _x	588	-
Hg ^d	2	-
As ^e	-	-
CO ₂	2,400,000 ^f	-

^aIn-situ complex produces 57,000 barrels of shale oil per day.

^bThe steam plant flow rate is 3454 MM scfd.

^cThe Stretford unit(s) preceding the steam plant are assumed to control H₂S levels in the gas stream entering the steam plant to 15 ppmv.

^dThe concentration of mercury in the steam plant flue gas is .027 ppm (by volume).

^eThe concentration of arsenic in the steam plant flue gas is .52 ppm (by weight).

^fEstimated from combustion of carbon compounds in flue gas, combustion of carbon residue on processed shale, and decomposition of dolomite. Presented as an order-of-magnitude estimate only.

References: Ashland Oil, Inc. and Occidental Oil Shale, Inc. Supplemental Material to Detailed Development Plan Modification for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. July 21, 1977.

Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. February, 1977.

concentrations in TOSCO II surface-retorted shale have been reported and are shown in Table 4-74. Element concentrations of in-situ retorted shales probably approximate those shown for surface-retorted shale. These concentrations are site-specific, depending on the composition of the raw shale being retorted. The mineral constituents of TOSCO II surface-retorted shale are shown in Table 4-75. The same constituents are probably found in in-situ retorted shale, and thus, in particulates emitted from the steam plant.

Polycyclic aromatic hydrocarbons are also found in particulate emissions from the steam plant. Those PAH detected in TOSCO II surface-retorted shale are reported in Table 4-76. The same PAH are likely to be found in in-situ retorted shale and in particulate emissions from the steam plant. All of the compounds in Table 4-76 are known or suspected animal carcinogens and may be carcinogenic to man. Concentrations of these compounds have not been reported.

Hydrocarbon emissions from the product shale oil storage tanks are shown in Table 4-91 as 103 lbs/hr.

Other emissions originate from the gas and wastewater treatment systems. Likely emission sources from the Stretford gas treatment units are the aeration basin, the sulfur separation tank, and the sulfur melter. Particulates and particles of elemental sulfur are possible emissions from the aeration basin. Oxidized and reduced vanadium compounds are also potential air pollutants. Emissions from the sulfur separation tank and the sulfur melter are largely particles of elemental sulfur. Sulfurous gases like hydrogen sulfide, carbon disulfide, and carbonyl sulfide are also potential pollutants.

Evaporation ponds are possible sources of the volatile compounds found in the various wastewaters. Atmospheric emissions from evaporation ponds have not been characterized, but are likely to contain ammonia and hydrogen sulfide.¹

Other emissions originate from oil/water separators. These emissions can be minimized by enclosing all components of the oil/water separation system.

4.6.2.3b Water Effluents

Water effluents from retorting/processing operations include water co-produced with the shale oil, cooling tower, boiler, and gas treatment blowdown waters, raw water treatment system wastewater, sanitary wastewaters, and underground leachate from retorted shale. Each of these water effluents is discussed below.

Water co-produced with shale oil comprises both free and bound water. Free water is easily separated from shale oil by decanting. Bound water is physically bound with the product oil in an emulsion, and is separated from the oil in heater/treaters. Occidental has estimated the amount of water co-produced with the shale oil to be 770 gpm for a 57,000 bbl/d facility. This amounts to about 0.50 barrels of water for each barrel of oil produced. The individual amounts of free and bound water constituting the 770 gpm have not been estimated. Approximate compositions of bound and free water are shown in Table 4-92. Current Occidental plans anticipate disposing of the co-produced

¹Crawford, K.W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976.

TABLE 4-92. APPROXIMATE COMPOSITIONS OF FREE AND BOUND
WATER CO-PRODUCED WITH SHALE OIL, MG/L

	Free ^{1,2}	Bound ^{3,4}
Cations		
Calcium	20	10-50
Magnesium	160	50-150
Sodium	650	250-650
Potassium	40	30-40
Ammonium	12,200	4-200
Anions		
Carbonates	6,300	0-100
Bicarbonates	26,100	100-3000
Sulfate	1,300	-
Sulfide	-	600-5000
Chloride	4,050	-
Gross Parameters		
BOD	-	100-14,000
COD	-	1,000-20,000
TOC	5,900	-
O&G	-	6-230
Total Solids	30,600	2,000-3,000
Phenols	-	0-210
pH	8.0-9.8	8.0-10.2
Trace Elements		
Arsenic	0.3	-
Cobalt	0.4	-
Boron	0.3	-
Vanadium	1.2	-
Titantium	0.2	-
Iron	0.5	-
Molybdenum	0.5	-
Tin	0.1	-
Rubidium	0.2	-
Strontium	0.1	-
Nickel	0.3	-

¹TRW Environmental Engineering Division and Denver Research Institute.
An Evaluation of Control Technologies for Treating Oil Shale Wastewaters.
Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881.
May 1977.

²Based on analyses of retort water from Laramie Energy Research Center's
10-ton simulated in-situ retort.

³TRW, *op.cit.*, p. 6.

⁴Bases not reported.

water in lined evaporation ponds. Extensive treatment would be required to upgrade the co-produced water for reuse.¹

Boiler water blowdowns are necessary to avoid the buildup of dissolved solids which can lead to scaling in the boiler. Occidental has estimated boiler water blowdowns for a 57,000 bbl/d facility to be 100 gpm (160 acre ft/year). Typical characteristics from boiler water blowdown are shown in Table 4-93. The boiler blowdown wastewater is normally routed to an evaporation pond.²

The composition of typical cooling tower blowdown wastewaters are presented in Table 4-93. Volumes of wastewater from cooling tower blowdowns have not been reported.

An undetermined quantity of liquid must be withdrawn from the Stretford gas treatment units as blowdown. This liquid contains dissolved and suspended particulates, vanadium compounds, elemental sulfur, and sulfur compounds. Required treatment techniques have not been specified, but probably include chemical treatment and filtration with disposal in an evaporation pond.

Volumes of wastewaters originating from raw water treatment systems have not been estimated. These wastewaters include backwash water from filtration, and blowdown from zeolite softening systems.³ Characteristics of these streams have not been reported.

¹Ashland Oil, Inc. and Occidental Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. February, 1977. pp. III-43 to 45, Figure III-J.

²*Ibid.*

³Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976.

TABLE 4-93. CHARACTERISTICS OF COOLING TOWER
AND BOILER WATER BLOWDOWNS

Parameter	Concentration, mg/l	
	Cooling Tower Blowdown	Boiler Water Blowdown
Total Solids	500-1500	1,000-10,000
Suspended Solids	10-50	10-50
Total Organic Carbon	5-15	10-50
PO ₄ -P	5-15	5-15
Cr	50-500	0.05-1.0
Zn	20-40	0.10-0.5
Fe	0.10-1.5	0.2-1.0

Source: TRW Environmental Engineering Division and Denver Research Institute. An Evaluation of Control Technologies for Treating Oil Shale Wastewaters. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. May 1977.

Sanitary wastewaters can be treated in package treatment units on-site, with recovery of the liquid effluent for reuse. Expected volumes of these sanitary wastes have not been reported but are probably insignificant.¹

A potential water pollution problem is the underground leaching of retorted shale. Inorganic salts, toxic metals, and some toxic organics (including carcinogens) are contained in the retorted shale and can be potentially leached from the shale. (Tables 4-74, 4-75, and 4-76 report the chemicals found in TOSCO II surface-retorted shale. In-situ retorted shale will have somewhat different characteristics because of the higher in-situ combustion temperature. The actual characteristics of in-situ retorted shale have not been reported.) Occidental believes that leaching problems can be avoided by: deliberate leaching of the shale followed by treatment and containment of the leachate; diversion of potential leachate by properly designing the outer areas of the mined area; or isolating retorted shale from potential leachate.² None of these techniques has been extensively tested.

4.6.2.3c Solid Wastes

No information has been reported on the quantity of solids generated from in-situ oil shale retorting/processing. Possibly the largest volumes of wastes are those of water and wastewater treatment sludges. These streams include chemical and lime sludges from the upgrading of water for process use. The sludges can be ponded for evaporation and/or chemically neutralized, and either combined with the mined-out shale, conveyed to the spent retorts, or disposed of offsite.³ The disposal of mined-out

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-b. Prepared for Area Oil Shale Supervisor. February, 1977. p. III-45.

²*Ibid.*, p. V-4.

³*Ibid.*, p. III-45.

shale was discussed in Section 4.5.3.3.

Sanitary wastes can be treated onsite, with recovery of the liquid effluent for reuse. The solids can then be discarded with other process solid wastes.¹

4.6.2.3d Noise Pollution

Noise at in-situ surface facilities originates from those sources shown in Table 4-94. Process blowers and steam boilers generate the highest levels of uncontrolled noise. Noise levels off-site should not be significantly affected by the in-situ operation.

Administrative controls can restrict the length of time workers are exposed to excessive noise. Worker exposure to noise can also be reduced by enclosing major noise sources (e.g., enclosing the process blowers). Other noise control measures are described in the literature. Surface noises associated with mining operations are discussed in Section 4.5.3.3.

4.6.2.3e Occupational Health and Safety

Health and safety hazards associated with retorting and processing operations at an in-situ complex have not been extensively examined. Safety hazards at the in-situ complex are similar to some hazards found at refineries. Health hazards are chiefly associated with worker exposure to raw

¹Ashland Oil, Inc. and Occidental Oil Shale, Inc. Modifications to Detailed Development Plan for Oil Shale Tract C-6. Prepared for Area Oil Shale Supervisor. February, 1977. p. III-45.

TABLE 4-94. NOISE LEVELS ENCOUNTERED BY NON-MINING PERSONNEL^a

Noise Source	Sound Level, dBA ^{b,c}
Process Blowers	95-110
Steam Generation Plant	95-103
Gas Treatment Plant	85-95
Water Treatment Facilities	80-93
Product Oil Treatment Facilities	70-80
Sulfur Recovery Facilities	70-80

^aAssumes acoustically untreated equipment.

^bAt 50' from noise source.

^cPreliminary sound level estimates.

Noise levels estimated by M. Lee Wilson (Radian Corporation) based on Radian noise files and from American Petroleum Institute, Guidelines on Noise, Medical Research Report No. EA7301, 1973.

and processed shale, shale oil, and toxic gases. These hazards are the same as those described in Section 4.6.1.3 for surface retorting.

4.6.2.3f Odors

Odors from shale retorting and processing include odors from sulfur oxides, nitrogen oxides, shale oil, and processed shale. These odors are described in Section 4.6.1.3.

The inputs and outputs associated with a modified in-situ plant are summarized in Table 4-95.

TABLE 4-95. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH
A MODIFIED IN-SITU PROCESSING PLANT PRODUCING
57,000 BPD OF SHALE OIL

Inputs

Manpower	
• operating	561 men
• peak construction ^a	2900 men
Materials and Equipment	
• gas and water treatment units	
• oil/water separators	
• product gas boilers	
Economics ^b	
• capital	\$306,000,000
• annualized operating	\$76,000,000
Water	2500 gpm
Land	80 acres
Ancillary Energy ^c	6.7 x 10 ⁸ kwh/yr

Outputs

Air Emissions	
• particulates	74 lb/hr
• hydrocarbons	120 lb/hr
• NO _x	588 lb/hr
• CO	84 lb/hr
• SO ₂	174 lb/hr
• CO ₂	2,400,000 lb/hr
Water Effluents	No direct discharge
Solid Wastes	Minor
Noise Pollution	
• at plant boundaries	Negligible
Occupational Health and Safety	Unknown
Odors	
• at plant boundaries	Negligible

^aPeak for all phases (including mine construction)

^b1977 dollars

^cPotentially supplied on-site

4.6.3 Modified In-Situ Processing with Surface Processing of Mined Shale

4.6.3.1 Technology

An alternate strategy for the recovery of oil shale is the combination of modified in-situ retorting with surface retorting of the shale mined to form the in-situ retorts. This strategy has been selected by developers of oil shale tract C-a, and may be chosen by developers of oil shale tract C-b. This section describes the combined application of modified in-situ and surface retorting technologies as envisioned by the developers of oil shale tract C-a (Gulf Oil Corporation and Standard Oil Company of Indiana). Conceptual design of the processing facility envisions a shale oil product suitable as a refinery feed. Other upgrading alternatives exist.¹

Since both retorting technologies have been discussed previously, the following discussion is only a summary description of the combined retorting development. The modified in-situ process selected by the developers of tract C-a is based on the RISE (Rubble In-Situ Extraction) process, previously described in Section 4.6.2.1c. Gulf Oil and Standard have tentatively selected the TOSCO II process for surface retorting. TOSCO II retorting technology has been described in Section 4.6.1.1a.²

Figure 4-29 is a block flow diagram showing the flow of major streams through the shale processing facility. After developmental mining (described in Section 4.5.3.1), air and

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 vols. Prepared for Area Oil Shale Supervisor. May 1977.

²*Ibid.*

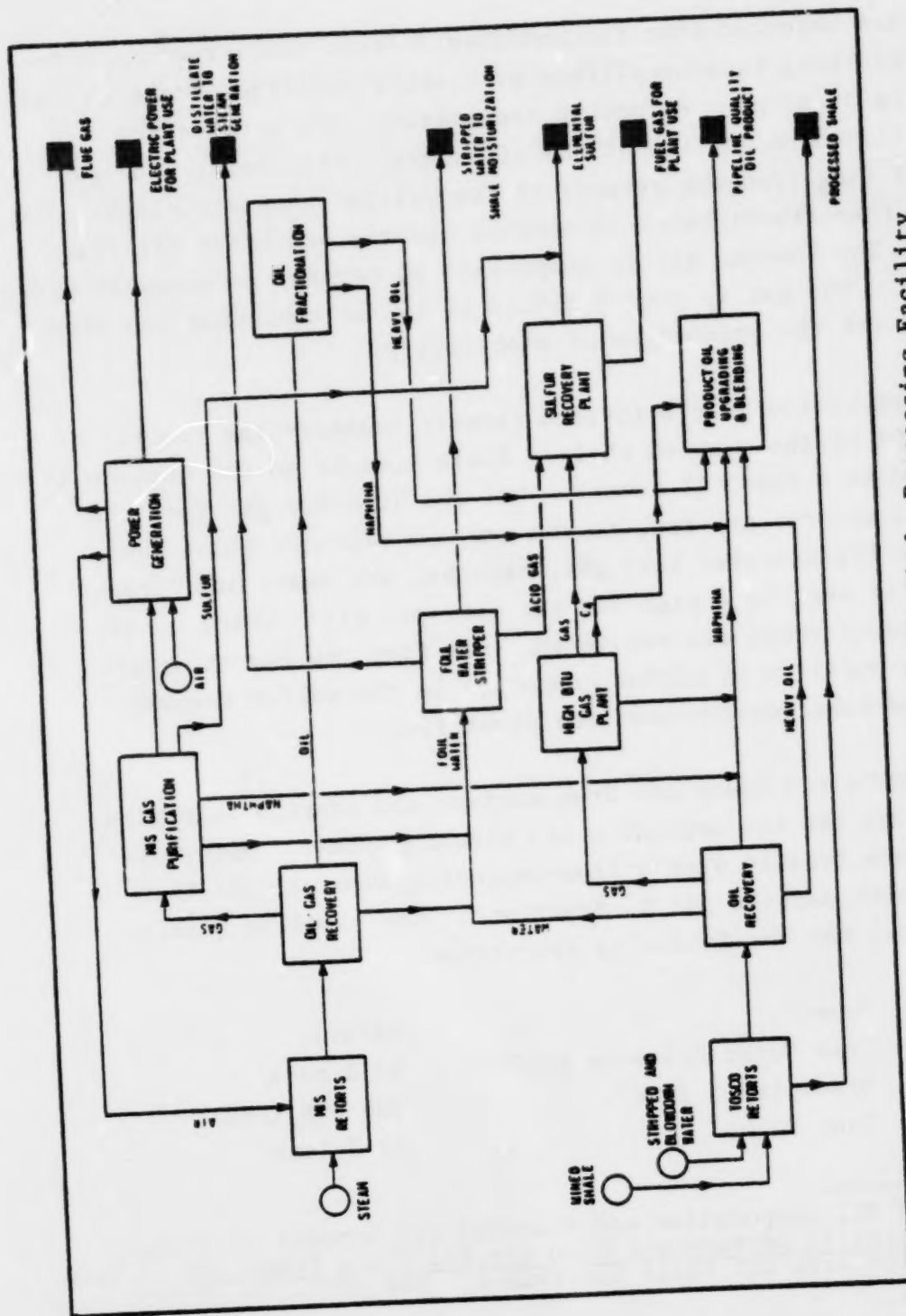


Figure 4-29. Flow Diagram of Oil Shale Processing Facility
Featuring Modified In Situ and Surface Retorting

Source: Gulf Oil Corporation and Standard Oil Company (Indiana).
Revised Development Plan for Oil Shale Tract C-a, 3 vols.
Prepared for Area Oil Shale Supervisor. May 1977.

steam are injected into the modified-in-situ (MIS) retorts. In-situ retorting is accomplished by heating rubblized shale in the presence of steam. Retorting temperatures are attained by a combustion of a portion of the oil shale. Oil, water and low-Btu gas flow from the retorts to the oil-gas recovery plant. The oil is then fractionated to produce naphtha and heavy oil fractions. The low-Btu gas is compressed to recover condensible hydrocarbons. The gas is then purified of sulfur compounds and used as fuel for the production of electricity.¹

Preparation of the in-situ retorts requires the removal of about 20% of the rubbled shale. Shale brought to the surface is retorted in a TOSCO II retort. Oil and high-Btu gas from the TOSCO II retorts are sent to the raw oil recovery plant where they are fractionated into gas, naphtha, and heavy oil streams. The gas is sent to a high-Btu gas recovery plant where condensible hydrocarbons are recovered. Gas from the gas recovery plant is purified of sulfur compounds in the sulfur recovery plant and subsequently used for plant fuel.²

Naphtha and heavy oil from surface and in-situ retorting are sent to the oil upgrading and blending plant. Heavy oil streams are treated with a flow-improving chemical and then blended with naphtha and C₄ fractions. The pipeline quality product oil has the following properties:

Gravity	26°API
True Vapor Pressure @ 100°F	11.2 psia
Viscosity @ 30°F	800 SUS (max)
Pour Point	30°F (max)

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 vols. Prepared for Area Oil Shale Supervisor. May 1977. p. 1-3-5.

²*Ibid.*

Elemental sulfur is produced in the gas purification and sulfur recovery plants.¹

Foul waters recovered from retorting operations are steam-stripped in the foul water stripping plant. The volume of stripped water is reduced by evaporation and then the water is used to moisturize processed shale. Distilled water is recycled to steam generation. Acid gas from the stripping plant is sent to the sulfur recovery plant.²

4.6.3.2 Input Requirements

Input requirements for the combined in-situ and surface retorting development have not been completely specified. Inputs reported by Gulf Oil and Standard Oil of Indiana are solely based on a conceptual design: no field testing of the RISE process has been performed.

Data reported below are based on a processing facility producing 76,000 BPD of a pipeline quality oil product. Of the 76,000 BPD, 57,000 BPD are to be produced by in-situ retorting with the remainder produced by TOSCO II surface retorting. The target oil shale has an average Fischer assay grade of about 23 gal/ton. Approximately 40,000 tons of shale are mined daily to create the required void space in the underground retorts.³

4.6.3.2a Manpower

Detailed manpower requirements have not been prepared by potential developers of the combined retorting facility. Total

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 vols. Prepared for Area Oil Shale Supervisor. May 1977. pp. 1-3-5 and 1-3-7.

²*Ibid.*, p. 3-3-3.

³*Ibid.*, p. 1-3-4.

requirements during commercial operations producing 76,000 BPD have been estimated at 2075. That employment estimate includes labor required for mining and shale feed preparation as well as retorting. Peak employment during construction of the entire facility has been estimated as 2500.¹

4.6.3.2b Materials and Equipment

Estimates of the materials and equipment required for the combined retorting facility have not been prepared. Plants comprising the commercial processing facility include TOSCO II retorts, oil and oil-gas recovery plants, gas purification and sulfur recovery plants, a foul water stripping plant, an oil fractionation plant, a power generation facility, a high-Btu gas plant, and a product oil upgrading and blending plant. These plants are shown in Figure 4-29.

4.6.3.2c Economics

No costs data have been reported by Gulf Oil and Standard Oil (Indiana).

4.6.3.2d Water

Table 4-96 summarizes the disposition of water involved in the normal operation of the combined retorting facility. Approximately 30% of the total water input is used for moisturizing processed shale from surface retorting. Evaporation and flue gas losses use essentially all of the remaining water input.²

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 vols. Prepared for Area Oil Shale Supervisor. May 1977. p. 1-1-19.

²*Ibid.*, p. 3-3-31.

TABLE 4-96. WATER BALANCE DURING NORMAL OPERATIONS
OF COMBINED RETORTING FACILITIES

	gpm
<u>Output</u>	
Water on Processed Shale	840
Surface Retort Vent Gas Loss	840
Cooling Tower Loss	330
Power Generation Plant Flue Gas Loss	610
Miscellaneous Loss	<u>130</u>
Total Output	2,750
<u>Input</u>	
Make-up Water	820
Water of Combustion	530
Retort Water and Residual Groundwater Inflow	<u>1,400</u>
Total Input	2,750

Source: Gulf Oil Corporation and Standard Oil Company (Indiana).
Revised Detailed Development Plan for Oil Shale Tract
C-a, 3 vols. Prepared for Area Oil Shale Supervisor.
May 1977. p. 3-3-31.

Approximately 820 gpm must be supplied by a local ground or surface water system.

4.6.3.2e Land

Land disturbances associated with the processing of shale include those areas comprising the processed shale disposal pile and the surface processing plant. Surface processing facilities require the commitment of approximately 240 acres. Processed shale disposal requires a total of 880 acres over the 30-year life of a commercial development. Corridors to the complex (including those for the mine) disturb about 280 acres.¹

4.6.3.2f Ancillary Energy

Energy requirements of the combined retorting facility have been estimated by Gulf and Standard Oil. Electric power production and consumption is summarized in Table 4-97. The power generation plant provides most of the requirements of the processing facility. Most of the electricity is generated on-site from low-Btu fuel gas from the in-situ retorts.

An estimated fuel balance is shown in Table 4-88.

Resource and energy recoveries for the combined retorting facility are approximately the same as those reported for Occidental's proposed development.

4.6.3.3 Outputs

Some residuals of the combined in-situ and surface retorting development have not been specified. Residuals reported by Gulf

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Trace C-a, 3 vols. Prepared for Area Oil Shale Supervisor. May 1977. p. I-6-19.

TABLE 4-97. ELECTRIC POWER PRODUCTION AND CONSUMPTION
FOR COMBINED RETORTING

Plant	Electric Power, MW	
	Consumed	Produced
In Situ Retorting		
Retorting	4	-
Oil-Gas Recovery	7	-
Oil Fractionation	5	-
Gas Purification	200	-
Power Generation		226
Surface Retorting		
TOSCO II	30	-
Raw Oil Recovery	1	-
High-Btu Gas Plant	7	-
Sulfur Recovery	1	-
Product Oil Blending	1	-
Foul Water Stripping	1	-
Support Systems	5	-
Purchased Power	-	36
Total	262	262

Source: Gulf Oil Corporation and Standard Oil Company (Indiana).
Revised Detailed Development Plan for Oil Shale Tract
C-a, 3 vols. Prepared for Area Oil Shale Supervisor.
May 1977. p. 3-3-29.

TABLE 4-98. ESTIMATED FUEL BALANCE
FOR COMBINED RETORTING

Plant	MM BTU/H	
	Produced	Consumed
a) High-Btu Fuel Gas		
TOSCO II Retorting Plant	-	819
High Btu Gas Plant	-	27
Sulfur Recovery Plant	882	9
Support Systems	-	27
	882	882
b) Low-Btu Fuel Gas		
In Situ-Produced Gas		
Purification Plant	3,260	-
TOSCO II Retorting Plant	-	171
Power Generation Plant	-	3,089
	3,260	3,260
Total Fuel Gas	4,142	4,142

Source: Gulf Oil Corporation and Standard Oil Company (Indiana).
Revised Detailed Development Plan for Oil Shale Tract
C-a, 3 vols. Prepared for Area Oil Shale Supervisor.
May 1977. p. 3-3-30.

and Standard (Indiana) are based solely on a preliminary design: no field testing of the RISE process has been performed.

4.6.3.3a Air Emissions

Atmospheric emissions from the combined retorting development originate from:

- 1) the TOSCO II pyrolysis and oil recovery unit,
- 2) the high-Btu gas plant reboiler,
- 3) the thermal oxidizer,
- 4) the power generation plant,
- 5) storage tanks, and
- 6) processed shale disposal.

Emissions from these sources are summarized in Table 4-99.

Fuel for the processing plant is supplied by purified high-Btu gas produced by TOSCO II retorting and low-Btu gas produced by in-situ retorting. About 99% of the ammonia and 98% of the sulfur compounds are removed from the high-Btu gas. The overall removals of sulfur compounds and ammonia from the low-Btu gas are about 98% and 90%, respectively.¹

The important emission sources are the TOSCO II retorting plant and the power generation plant. Flue gases from the pre-heating systems are scrubbed in high energy venturi scrubbers

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 vols. Prepared for Area Oil Shale Supervisor. May 1977. p. 1-6-8.

TABLE 4-99. ESTIMATED EMISSIONS FROM COMBINED RETORTING DEVELOPMENT

Source Description	Preheat System	Superheater-Ball Circ.	Shale Moisturizing	High-Btu Gas Plant Reboiler	Thermal Oxidizer	Power Generation Plant	Tank Vapor Losses	Processed Shale Disposal
No. of Stacks	3	3	3	1	1	2	-	-
Stack Height, Ft.*	330	330	330	150	150	330	-	-
Stack Diameter, Ft.	12.0	6.0	3.0	3	9.5	35	-	-
Stack Gas Parameters								
Gas Flow								
LB/HR	1,815,000	384,000	212,000	20,700	280,000	10,000,000	-	-
ACFM	603,000	156,000	111,300	13,800	128,000	4,450,000	-	-
Molecular Weight	27.7	25.6	19.9	28.2	22	30.5	-	-
Exit Temperature, °F	122	200	200	730	180	400	-	-
Moisture Content, Vol %	16	31	83	-	66	5	-	-
SO ₂ Content								
LB/HR	42	0.6	-	0.3	31	384	-	-
PPM (Vol)	10	2.3	-	3	38	18	-	-
LB/MMBTU fired	0.046	0.015	-	.007	1.1	0.12	-	-
NO _x Content								
LB/HR	429	21	-	8	50	1,860	-	-
PPM (Vol)	143	30	-	225	85	123	-	-
LB/MMBTU fired	0.047	0.54	-	0.35	1.9	0.57	-	-
Particulates								
LB/HR	120	21	10	0.3	0.7	320	-	11
Grains/ACF	0.023	0.016	0.031	0.003	.006	0.1	-	-
Hydrocarbons								
LB/HR	147	-	-	0.6	0.7	20	6	-
CO ₂								
LB/HR	150,000	2,500	-	4,000	5,000	2,100,000	-	-
Firing Duty, MMBTU/HR	807	13	-	22	27	3,260	-	-

*Measured from grade at TOSCO Retorting Plant.

Note: Carbon monoxide content in stack gases is negligible; carbon dioxide emissions presented as order-of-magnitude estimates, calculated from carbon content of fuels, combustion of carbon residual on processed shale, and de-composition of dolomite.

Emission from feedstock preparation, materials handling, and mine ventilation are discussed in Sections 4.5.3.3 and 4.5.1.3.

Source: Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 vols. Prepared for Area Oil Shale Supervisor. May 1977. p. 3-3-33.

prior to release to the atmosphere. Caustic is injected into the wet scrubbers to reduce the concentration of sulfur dioxide in the flue gases to a concentration of 10 ppmv. The TOSCO II pre-heat system contains an incinerator to remove 90 to 95% of the hydrocarbon vapors contained in the flue gas.¹

Flue gases from the ball circulation and shale moisturizing systems are also scrubbed before release to the atmosphere. Entrained shale dust is removed from the flue gas in high energy venturi scrubbers.²

Emissions from power generation are controlled by the use of purified fuel gas. This purified gas is prepared from gas produced during in-situ retorting.³

Hydrocarbon emissions from oil storage tanks are controlled by using floating roof tanks for the more volatile liquids.⁴

4.6.3.3b Water Effluents

The developers of tract C-a expect no discharge of process wastewater into the environment. A portion of the water produced is consumed through evaporation, processing needs, dust control needs, and by adsorption in the processed shale. Most of the groundwater from mine dewatering is pumped and reinjected into the aquifer system. Surface waters originating within the

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 vols. Prepared for Area Oil Shale Supervisor. May 1977. p. 1-6-8.

²*Ibid.*, p. 1-6-9.

³*Ibid.*, p. 1-6-9.

⁴*Ibid.*, p. 1-6-9.

plant area are controlled by a series of collection ditches and retention dams. Surface waters are ultimately recycled to the process water system, used for dust control, or evaporated.¹ Groundwater may be fouled by leachate from the underground retorts.

4.6.3.3c Solid Wastes

Moisturized processed shale is produced at the rate of 36,000 TPD.² The entire production must be disposed on the surface, unless a portion can be used to backfill the in-situ retorts.

Other solid wastes are tabulated in Table 4-100. Spent zeolites and lime sludge from water treatment can be disposed of in the processed shale disposal pile. The spent catalysts are recycled to the manufacturer.³

4.6.3.3d Noise Pollution

4.6.3.3e Occupational Health and Safety

4.6.3.3f Odors

These outputs have been extensively discussed in Sections 4.6.1.3 and 4.6.2.3 on surface and in-situ retorting. Similar discussions describe the combined modified in-situ and surface retorting developments.

Inputs and outputs associated with the combined in-situ and surface retorting developments are found in Table 4-101.

¹Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 vols. Prepared for Area Oil Shale Supervisor. May 1977. pp. 6-6-1, 6-6-2.

²*Ibid.*, p. 1-3-7.

³*Ibid.*, p. 6-9-4.

TABLE 4-100. NON-SHALE SOLID WASTES

Process Unit	Solid Waste Description	Approximate Quantity* TPY
Sulfur Recovery		
Claus Unit	Spent oxidation catalyst	45
Tail Gas Unit	Spent hydrogenation catalyst	8
Water Treating		
	Spent zeolites	3
	Lime sludge	870

*Average over catalyst life.

Source: Gulf Oil Corporation and Standard Oil Company (Indiana). Revised Detailed Development Plan for Oil Shale Tract C-a, 3 vols.
Prepared for Area Oil Shale Supervisor. May 1977. p. 6-9-4.

TABLE 4-101. SUMMARY OF INPUTS AND OUTPUTS ASSOCIATED WITH A
MODIFIED IN-SITU AND SURFACE PROCESSING PLANT
PRODUCING 76,000 BPD OF SHALE OIL

<u>Inputs</u>		
Manpower		
• operating	1000	
• peak construction ^a	2500	
Materials and Equipment		
• TOSCO II retorts		
• oil and oil-gas recovery units		
• gas purification and sulfur recovery units		
• foul water stripper		
• oil fractionation and high Btu gas units		
• oil upgrading and blending units		
Economics	Unknown	
Water	2750 gpm	
Land		
• surface processing facilities	240 acres	
• shale disposal (over 30 years)	900 acres	
• corridors (including mine)	280 acres	
Ancillary Energy	3.2 x 10 ⁸ kwh/yr	
<u>Outputs</u>		
Air Emissions		
• particulates	483 lb/hr	
• hydrocarbons	174 lb/hr	
• NO _x	2370 lb/hr	
• CO	--	
• SO ₂	458 lb/hr	
• CO ₂	2,250,000 lb/hr	
Water Effluents	No direct discharge	
Solid Wastes		
• processed shale	36,000 TPD	
• catalysts and sludges	820 TPY	
Noise Pollution		
• at plant boundaries	Negligible	
Occupational Health and Safety	Unknown	
Odors		
• at plant boundaries	Negligible	

^aPeak for all phases (including mine construction)

4.6.4 Processing Social Controls

Regulations for energy processing facilities are concerned with environmental impacts, safety and health of employees, and control of the processed product. This section will discuss the federal and state regulations which apply to the processing of oil shale. These regulations consider initial planning and land use, water quality, air quality, solid wastes, noise, safety, and the regulation of product output.

4.6.4.1 Plans and Land Use

Under the Prototype Oil Shale Leasing Program, environmental baseline data pertaining to the quantity and quality of surface water, ground water, the quality of air, and the population relationships of flora and fauna must be collected for at least one year prior to the submission of a detailed development plan and for one additional year prior to commercial operations. The lessee is also required to submit the results of environmental monitoring for public release on an annual basis. Public hearings on the environmental aspects of the detailed development plan were conducted by the Area Oil Shale Supervisor (AOSS). The Oil Shale Environmental Advisory Panel acts as a review body to provide guidance to the AOSS and the appropriate BLM district managers.

4.6.4.2 Water Quality

Because facilities described in the technological summaries have no effluents,¹ the laws applicable to surface water effluents, do not apply. Hence, the FWPCA and its respective state laws will not apply. Laws that do apply are those concerned

¹Sections 4.6.1.3b, 4.6.2.3b, 4.6.3.3b.

with holding ponds, such as the federal drinking water regulations and state laws on retaining ponds and groundwater, all of which are described in the water quality section of Chapter 2.

4.6.4.3 Air Quality

The air quality controls applicable to oil shale processing are included in the Environmental Stipulations of the Prototype Oil Shale Leases.¹ These include a requirement for compliance with applicable stipulations of both federal and state air quality and emission regulations (described in Chapter 2), a requirement to avoid or minimize dust problems, and a prohibition against burning waste, timber, or debris unless other methods of disposal would be more harmful to the environment.²

4.6.4.4 Solid Wastes

The disposal of solid wastes is regulated by the controls discussed in Section 4.5.4.3. Because oil shale processing will result in a large solid waste problem, the regulation of that output starts prior to any production of the waste. The development plan, including waste disposal, must be approved prior to operation.

4.6.4.5 Safety and Health

Health and safety regulation for oil shale processing is regulated by OSHA at the retort site, although MSHA has authority

¹U.S. Department of the Interior. Final Environmental Impact Statement for the Prototype Oil Shale Leasing Program. Volume III. pp. V-43 to V-84.

²*Ibid.*, p. V-69.

over oil shale crushing, pulverizing and sizing of oil shale.

Outside of normal safety and health problems associated with any processing facility, an additional problem is the carcinogenic property of the raw shale oil. No specific controls exist.

4.6.4.6 Noise

Noise control in oil shale processing is generally similar to noise regulation in most other energy processing (e.g., coal). As shown in Table 4-102, various agencies and governments are involved in noise control.^{1,2} Additionally, it should be noted that the environmental stipulations require the federal oil shale lessees to comply with all present and future noise standards.³

4.6.4.7 Product Regulation

Product regulation of oil shale and its products, which are in fact oil, should be no different than that discussed in Chapter 6. Pricing, however, is included within the synthetic fuels entitlement program which provides a subsidy of approximately \$2/bbl.⁴ Additional supports of \$3/bbl have been proposed by Senator Talmadge in negotiations on President Carter's energy package.⁵

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-62.

²Note also that the applicable standards for mining and also the Colorado standards are discussed in Chapter 2.

³Section 10 of the Environmental Stipulations.

⁴Energy Users Report, May 18, 1978, p. 5.

⁵Denver Post, September 22, 1977.

TABLE 4-102. NOISE POLLUTION CONTROL STANDARDS

Government Agency	Applicable Noise Pollution Standard
<u>Federal</u>	
Environmental Protection Agency (EPA)	40 CFR Part 202 - Motor Carriers Engaged in Interstate Commerce Effective October 15, 1975 40 CFR Part 204 - Noise Emission Standard for Construction Equipment - Standards for Air Compressors Effective January 1, 1978.
U.S. Mine Enforcement Safety Administration (MESA)	30 CFR Part 57 - Health and Safety Standards, Metal and Non-metallic Underground Mines
Occupational Safety and Health Administration (OSHA)	29 CFR Part 1910 - Occupational Safety and Health Standards
OSHA	29 CFR Part 1926 - Occupational Safety and Health Regulations for Construction
<u>State</u>	
Colorado	Colorado Revised Statutes, 1973, §25 - 12 - 101 to §25 - 108
Proposed Noise Standards	
EPA	40 CFR Part 205 - Transportation Equipment Noise Emission Controls

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-62.

4.7 LAND RECLAMATION

Surface disturbances associated with oil shale development include those attributed to:

- 1) construction and operation of surface facilities,
- 2) mining activities,
- 3) overburden removal,
- 4) development of utility corridors, and
- 5) processed shale disposal.

Reclamation of land disturbed by the first four activities requires reclamation techniques similar to those applied in coal development. Since these techniques are already commonly used in the coal industry and have been discussed in Chapter 3, they are not discussed here.

Reclamation of land disturbed by the disposal of large quantities of processed shale requires the application of special reclamation techniques. These techniques are briefly described in the following sections.

Section 4.7.1 discusses those characteristics of processed shale that affect its disposal and reclamation. Section 4.7.2 discusses some techniques applicable to the disposal and reclamation of processed shale.

4.7.1 Characteristics of Processed Shale

The various retorting techniques produce processed shales with varying physical and chemical characteristics. Typical properties of several shales are shown in Table 4-103. Mineral compositions of retorted shales have been reported in Table 4-75. Table 4-74 reports concentrations of elements found in TOSCO II retorted shale. Table 4-76 identifies certain polycyclic aromatic hydrocarbons found in TOSCO II retorted shale.

Typical retorted shales from internal combustion gas retorts have compositions similar to that of Portland cement. These processed shales are soft and friable, and have organic carbon contents of 2 to 3% or lower, depending on the retorting process. The cement-forming tendency of these processed shales can help to create a physically and chemically stable disposal pile. Before setting, the retorted shale behaves like a sandy silt. After setting, it develops sufficient cohesion to allow the construction of deep, well-stabilized piles with high slope angles. The strength of the disposal pile depends on the amount of moisture added (10-14% is optimum) and the amount of cohesive hydrates produced. Reduction of particle size increases pile strength.^{1,2}

Retorted shales from indirect-heated retorts (e.g., TOSCO II, Union B, Paraho Indirect Mode) have organic carbon contents of 4 to 5%. Cementation reactions do not occur during compaction of these retorted shales, except through the cohesion produced

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976.

²Nevens, T. D., W. J. Culbertson and R. D. Hollingshead. "Disposal and Uses of Oil Shale Ash", USBM Project SWD-8, 1967.

TABLE 4-103. PROPERTIES OF RETORTED SHALES

	USBM Gas Combustion	TOSCO II	Union A	Union B
Geometric mean size, cm	0.205	0.007	--	--
Bulk density, g/cm ³	1.44	1.30	1.80	0.98
Solids density, g/cm ³	2.46	2.49	2.71	--
Porosity	0.41	0.47	--	--
Permeability, cm ²	3.46x10 ⁻⁹	2.5x10 ⁻¹⁰	--	--

Note: Bulk density before compaction.

Sources: Ward, J. E. et al. "Water Pollution Potential of Rainfall on Spent Shale Residues", Colorado State University, Prepared for U.S. Environmental Protection Agency under grant #14030 EDB, December 1971.
Lipman, S. C. "Union Oil Company Revegetation Studies", Environmental Oil Shale Symposium, Colorado School of Mines, October 9-10, 1975.

by compaction alone. Leaching of soluble salts, metals, and organics is thus more likely than for direct-heated shales.¹

4.7.2 Disposal and Reclamation of Processed Shale

This section briefly describes methods for the disposal and reclamation of processed shale. The discussion is largely a summary of a discussion presented by Conkle et al.²

The cooled and moistened shale from surface retorting will typically be conveyed to adjacent canyons or other topographic depressions. The processed shale will then be compacted to maintain stability as the pile is built up. To prevent downstream pollution by leaching of soluble material from the processed shale, disposal areas must be safe-guarded by dams, culverts, and/or diversion ditches.

Erosion of processed shale piles may be lessened to some extent through physical, chemical, and vegetative methods of stabilization. Physical methods include covering the processed shale pile with topsoil. Chemical stabilization methods involve reacting the shale with a reagent to form a water and air impermeable crust or layer. Vegetative stabilization usually requires the application of six or more inches of topsoil to the processed shale, but varies with the type of processed shale and the use of an artificial capillary barrier.

¹Crawford, K. W., et al. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Prepared for U.S. Environmental Protection Agency. Contract No. 68-02-1881. Denver Research Institute and TRW Environmental Engineering Division. June 1976.

²Conkle, N., V. Ellzey, and K. Murthy. Environmental Considerations for Oil Shale Development. Battelle Columbus Laboratories. Prepared for U.S. Environmental Protection Agency. October 1974. pp. 68-71.

Disposal of the processed shale by slurring and pumping to a disposal pond is attractive because of the relative simplicity and low cost of the system. Such disposal is limited by inadequate disposal areas and water availability. This disposal technique is impractical for the disposal of large quantities (approximately 53,000 TPD) of processed shale.

Some of the processed shale may be disposed of in mined-out areas underground. Because the processed shale has a larger specific volume than raw shale, a maximum of 70 percent of the total volume of processed shale may be disposed of underground unless other minerals have been recovered from the shale. Both conveyor and slurry methods for underground disposal have been proposed.

The susceptibility of the shale pile to water leaching can be limited by proper disposal site construction and compaction. If water and runoff are collected in catchment ponds, pollution of surface waters can be minimized. Additional protection (pond lining) must be provided to avoid pollution of groundwater.

Water requirements for revegetation of processed shale disposal piles vary with the type of retorted shale. Developers of planned 50,000 BPD TOSCO II facilities have indicated that 70 gpm (110 acre-ft/year) are required during the first twelve years of shale disposal: most of the water is probably used for dust suppression. When intensive revegetation efforts commence, up to 700 gpm (1100 acre-ft/yr) are required.^{1,2} These water requirements amount to 2-20 gallons per ton of processed shale. Little water is required for the revegetation of raw shale piles.

¹Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b, Volume I, Prepared for Area Oil Shale Supervisor. February 1976. p. IV-63.

²U.S. Bureau of Land Management. Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Draft Environmental Impact Statement. DES-75-62. Washington, D.C.: December 1975.